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PRELIMINARY EMISSIONS ASSESSMENT OF CONVENTIONAL STATIONARY COMBUSTION SYSTEMS

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16. ABSTRACT

The report gives results of a preliminary emissions assessment of the air, water, and solid waste pollutants produced by conventional stationary combustion systems. It gives results in four principal categories: utilities (electric generation), industrial (steam generation, space heating, and stationary engines), commercial/institutional (space heating and stationary engines), and residential (space heating). For each principal combustion system category, it gives: process types and operating efficiencies, fuel consumption, pollutant sources and characteristics, major research and development trends, fuel consumption trends, and technical areas where emission data are incomplete or unreliable. It also gives the pollutant emissions from applicable unit operations for each of 56 source classifications, using a uniform combustion source classification system. It identifies major gaps in available data regarding the population and capacity of combustion systems, application of control measures, fuel composition, and other parameters which significantly influence pollutant characteristics and emission rates.

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Combustion	Power Generation	Stationary Sources	21B	10A
Utilities	Space Heating	Emissions Assessment		13A
Industries	Stationary Engines		05C	21G
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VOLUME II--FINAL REPORT

by

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SECTION I

INTRODUCTION AND SUMMARY

PROGRAM OVERVIEW

The overall objective of this project was to prepare a preliminary emission assessment of conventional stationary combustion sources. The word conventional is meant to indicate technology which is currently in use and which is based on common fossil fuels; i.e., coal, oil, natural gas, or solid wastes such as those derived from agricultural, forestry or municipal refuse. Emissions from nuclear energy or systems such as fluidized bed combustion, magnetohydrodynamics, fuel cells, etc., which are currently being developed, have not been included.

The emission of pollutants to air and water and the generation of solid waste by conventional stationary combustion systems were assessed in this program. The assessment was confined to emissions resulting from operations and processes at the combustion site and did not include remote effects such as those arising from mining and transportation.

Four principal categories of conventional stationary combustion systems were considered:

- Utilities - electric generation
- Industrial - steam generation, space heating, and stationary engines (direct heating and chemical conversion were excluded)
- Commercial/Institutional - space heating and stationary engines
- Residential - space heating.

The principal combustion categories were further divided into subcategories according to a classification scheme based on fuel type, combustion unit type, firing technique, thermal rate, fly ash reinjection, and application of control measures or devices. A total of 56 of the combustion system subcategories were selected for emphasis in the contract investigations. These subcategories were chosen for study because preliminary analyses indicated that: they are now, or potentially could be in the future, the largest sources of pollutant emissions; and they represent the most widely used systems included in the classification scheme.

Emission estimates for these selected systems were calculated and are presented, on a unit operations basis, in a series of emission summary tables. The tables are supplemented by text which presents the methodologies used to derive the emissions, and analyzes the extent and quality of available data. Each principal category - electric utilities, industrial, commercial/institutional, and residential - is treated in a separate section. Trend information and a discussion of on-going and planned activities dealing with emissions from conventional stationary sources are presented in the final two sections of this document.

The data presented in the emission summary tables are national estimates and provide guidelines for determining the magnitude of the air, water, and solid waste problems associated with the conventional stationary combustion sources and their pertinent unit operations. Emission streams will exhibit plant-to-plant variations due to such factors as the type of fuel used, boiler type and load, plant operational practices, etc.

The major unit operations or processes that were utilized as the basis for summarizing air and water emissions and solid waste are:

- Flue gas emissions
- Ash handling
- Cooling systems
- Water treatment
- Fuel handling
- Flue gas desulfurization.

The major pollutants for which emission estimates have been derived are:

- Air:
  - Particulates
  - Sulfur oxides (SO_x)
  - Nitrogen oxides (NO_x)
  - Hydrocarbons (HC)
  - Carbon monoxide (CO)

  - Trace elements (28 elements)

  - Benzene soluble organics (BSO)*
  - Particulate polycyclic organic matter (PPOM)
    - Benzo(a)pyrenes (BaP)
  - Polyhalogenated hydrocarbons (PHH)
    - Polychlorinated biphenyls (PCB)
    - Polybrominated biphenyls (PBB)
  - Radioactive elements

- Water:
  - Total solids (TS)
  - Suspended solids (TSS)
  - Dissolved solids (TDS)
  - pH

  - Trace elements

- Solid:
  - Bottom ash
  - Fly ash
  - Desulfurization solids

  - Trace elements.

The emission estimates presented in the emission summary tables were based on a survey of data existing in the literature and information supplied through contact with members of industrial, governmental, and academic laboratories. A major use of these estimates will be to develop a preliminary priority ranking of the selected combustion systems based on the total emissions of these systems for the pollutants noted above.+ To assist in the development of the priority ranking, fuel consumption and composition data by state and/or region, by the four principal combustion categories, were developed.

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*A list of acronyms used in this report is presented in Appendix G.

+This priority ranking activity is being conducted for the EPA, Industrial Environmental Research Laboratory, by Monsanto Research Corporation, Dayton, Ohio, under Contract No. 68-02-1404, Task Order No. 18.

In addition to providing estimates of emissions from conventional stationary combustion sources, the contract effort involved development of the following data:

- State-of-the-art developments in combustion technology with respect to efficiency and pollutant generation.
- The number, type, location, and size of the combustion systems within the United States based upon the selected combustion classification system.
- Trends in fuel consumption and boiler design and their impacts on emissions.
- The extent and quality of available emission data.
- Identification of the major gaps in available pollutant data with respect to: types of combustion systems, unit operations within combustion systems, fuel composition, and other parameters which can affect the composition and quantity of pollutant emissions.
- Identification of current and planned activities associated with emissions from conventional stationary combustion sources.

These data were deemed to be essential for a comprehensive assessment of the environmental impact of conventional combustion systems. Although the work described in this report is only a first step toward obtaining the information necessary for such an overall assessment, it enumerates the major gaps in the data base and allows decisions to be made concerning the additional work required to fill the data base gaps.

EMISSION SUMMARIES

The following discussion summarizes the contribution of the combustion sources to total national emissions and also provides an overview of the relative contributions of each of the four principal combustion system categories.

Fuel consumption by the principal categories of combustion sources is shown in Table 1. Coal accounted for approximately 26 percent of the combustion-released energy generated, but, based on emission data presented later in this report, produced approximately 90 percent of the particulate, 75 percent of the SO_x, 50 percent of the NO_x, and 80 percent of most trace elements emitted to the atmosphere by the combustion systems considered in this study. Coal furnished 55 percent of the energy used by the combustion-based electric utilities, 10 percent of the industrial stationary combustion energy, and only 3 percent and 2 percent of the combustion released energy used in commercial and residential sources, respectively. Natural gas was the primary fuel (greater than 65 percent of the total) in both the industrial and residential sectors. Gas represented 47 percent of the fuel used; the only major air pollutant produced from this fuel was NO_x, representing 27 percent of the total.

Major emissions to air and water and solid waste generated by the four principal categories are presented in Table 2. Total emissions are presented along with the percentage contribution of the principal categories.

Electric generation is the principal source of the criteria and trace air pollutants from conventional stationary combustion systems. The major source of carbon monoxide and organics is residential combustion, suggesting that residential units burn fuel incompletely, and that efforts to improve the combustion efficiency of those myriad small sources are needed. Although representing only 2 percent of the fuel consumed by residential sources, coal is the major source of these emissions.

Emissions of polycyclic organic matter (POM) and polyhalogenated biphenyls (PHB) have not been extensively measured. POM emissions, on the basis of limited testing, are largely due to incomplete combustion, and as a result are attributable principally to low efficiency residential heating units. Only one reference reported data for emissions of polychlorinated

Table 1. FUEL CONSUMPTION, CONVENTIONAL STATIONARY COMBUSTION SYSTEMS (10^{12} Btu/year)[a]

	Utilities (1974)	Industrial (1973)	Commercial (1973)	Residential (1973)	Total
External combustion	14,798	8,540	4,450[d]	8,057[e]	35,845
Coal	8,502	1,370	156	192	10,220
Bituminous	8,264	1,320	101	115	9,800
Anthracite	38	10	55	75	178
Lignite	200	40	-	2	242
Petroleum	3,039	1,700	2,379	2,280	9,398
Residual	2,901	1,270	1,269	0	5,440
Distillate	138	430	1,110	2,280	3,958
Natural gas	3,257	5,200	1,914	5,450	15,821
Internal combustion	589	2,760	50	0	3,399
Distillate oil	312	360	25	0	692
Natural gas	277	2,400	25	0	2,702
Total	15,387[b]	11,300[c]	4,500[d]	8,057[e]	39,244

[a] Although it is EPA's policy to use the metric system for quantitative descriptions, the British system is used in this report because the data were originally reported in British units. Readers who are more accustomed to metric units may use the table of conversions., Appendix F.

[b] Solid Refuse fuel provided < 0.005 percent of this total.

[c] Includes 20×10^{12} Btu of bagasse and 250×10^{12} Btu of wood as fuel.

[d] Includes 1×10^{12} Btu of wood as fuel.

[e] Includes 135×10^{12} Btu of wood as fuel.

Table 2. MAJOR EMISSIONS FROM CONVENTIONAL STATIONARY COMBUSTION SYSTEMS

	Air								Water			Solid waste		
						Organics[a]								
	Particulates, %	SO_x, %	NO_x, %	HC, %	CO, %	BSO, %	PPOM, %	BaP, %	Total solids, %	Dissolved solids, %	Waste heat, %	Total ash, %	Fly ash, %	Desulfurization solids, %
Electric Generation	63.8	72.5	64.8	34.0	33.6	8.8	0.3	0.2	94	94	80	87	94	94
Industrial	28.3	14.5	24.7	22.3	14.9	20.0	0.5	1.3	6	6	20	10	6	6
Commercial/ Institutional	4.9	6.7	7.3	12.2	7.7	16.0	0.2	0.4	< 1	< 1	< 1	1	< 1	0
Residential	3.0	6.3	3.2	31.5	44.7	55.2	99.0	98.1	NIL	NIL	NIL	2	0	0
Total, 10^3 ton/yr	7,060	22,100	10,950	353	1,070	125	4.14	0.40	5,000	3,700	7.9×10^{15} Btu/yr	54,000	36,000	3,500

[a] BSO = Benzene soluble organics
PPOM = Particulate polycyclic organic material
BaP = Benzo(a)pyrene
Does not include emissions of polyhalogenated biphenyls.
Total estimated emissions of polychlorinated biphenyls based on a single emission measurement is ~10 tons per year from coal-fired utility boilers.

biphenyls (PCB) from combustion.[1] The average emission rate from a 125 MW pulverized coal-fired boiler was 0.8 mg/10^6 Btu. Assuming the same emission rate for all coal-fired boilers, the total PCB emissions from coal would be 7.5 tons/year. No data were found for emissions of polybrominated biphenyls (PBB) from coal, and no data were found for any polyhalogenated hydrocarbon (PHH) emissions from oil or gas. Because of the known toxicity of these compounds and their persistence in the environment, further work is necessary to identify the contribution of all combustion sources to existing environmental levels.

The largest contributions to the burden of suspended and dissolved solids discharged to water (approximately 5 million tons/year from all stationary combustion sources) result from water used for coal ash handling. Ash handling waste water contains an estimated 2.3 million tons of solids, largely in dissolved form. Waste water from boiler feedwater treatment is also a significant contributor from the utility sector because of stringent boiler water quality requirements. Over 90 percent of the water pollutants resulting from stationary combustion are a by-product of electric utilities.

Ash production is approximately 54 million tons/year, with electric utilities contributing 87 percent of the total and with coal ash constituting the major solid waste material.

In order to place conventional stationary combustion source emissions in perspective, Table 3 summarizes the air emissions of the criteria pollutants from the combustion sources considered in this study along with other man-made and natural sources of emissions in the United States. Conventional stationary combustion sources are seen to be the largest emitters of sulfur oxides and major emitters of airborne particulates and nitrogen oxides, whereas their contribution to hydrocarbon and carbon monoxide emissions is of minor significance.

Table 3. MAGNITUDE OF AIR EMISSIONS FROM CONVENTIONAL STATIONARY COMBUSTION SOURCES COMPARED TO ALL MAN-MADE AND NATURAL EMISSIONS IN THE U.S.[a]

Source	Particulates			Sulfur oxides			Nitrogen oxides			Hydrocarbons			Carbon monoxide		
	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made	10^6 ton/yr	% of total	% of man-made
Nature[b]	U[c]	U	-	4.2	11.9	-	U	U	-	30.7	45.5	-	NONE	0	-
Stationary Combustion	7.1	U	20.4	22.1	62.6	71.0	11.0	U	44.3	0.4	0.5	1.0	1.1	0.7	0.7
Transportation	0.8	U	2.3	1.1	3.1	3.5	11.2	U	45.2	19.8	29.3	53.7	111.5	74.0	74.0
Industrial Processes	14.4	U	40.5	7.5	21.3	24.2	0.2	U	0.8	5.5	8.1	14.9	12.0	8.0	8.0
Miscellaneous	12.8	U	36.4	0.4	1.1	1.3	2.4	U	9.7	11.2	16.6	30.4	26.1	17.3	17.3
Total	35.1	U	100.0	35.3	100.0	100.0	24.8	U	100.0	67.6	100.0	100.0	150.7	100.0	100.0

[a] Estimates for combustion sources studied in this program were developed by GCA, other emissions based on Robinson and Robbins[2] and Walther.[3]

[b] Natural emissions estimated by multiplying total natural emissions by the ratio of U.S. to global land surface areas.

[c] U = Unknown.

Trace element emissions to air from all fuels are summarized in Table 4. Electric generation by stationary combustion is again the source of most of these emissions, largely as a result of the combustion of coal. Although not shown by the table, only cadmium, cobalt, copper, nickel, and vanadium of the 28 trace elements tabulated are produced in appreciable quantities by burning oil. Analysis of the available emission data indicates that approximately 50 to 80 percent of the combustion source emissions of these elements are attributable to oil combustion.

Sources of trace metal element emissions to water are ash pond discharge, cooling tower waters, and waste water from boiler water treatment processes. Because of differences in system design and operating practices, trace element emissions to water exhibit large variability. Because of this variability, and the lack of sufficient emissions data, it has not been possible to compile trace element data for water in a manner similar to that presented in Table 4 for air. However, it is estimated that over 95 percent of trace metals from combustion sources (and over 90 percent of organic compounds), are the result of electric utility operations. The utility industry is estimated to contribute 14 percent of the total national discharge of metals, including 50, 14, 10 and 21 percent of chromium, copper, iron, and zinc discharged by industries designated as major water pollutant sources by EPA.[4]

Electric coal-fired utilities are the principal source of solid waste trace elements. The predominant sources of solid waste trace elements are bottom ash, fly ash, and solids produced by SO_2 recovery systems, whose combined production is now approximately 54 million tons per year. This value will increase with increasing coal consumption and will increase several fold if predictions concerning flue gas desulfurization utilization are realized. The trace element content of collected ash is summarized in Table 5.

Table 4. TRACE ELEMENT AIR EMISSIONS: PERCENT OF TOTAL FROM CONVENTIONAL STATIONARY COMBUSTION SYSTEM CATEGORIES

	Sb	As	Ba	Be	Bi	B	Br	Cd	Cl
Electric Generation	87	90	88	89	91	90	84	61	83
Industrial	10	8	9	9	7	9	13	21	13
Commercial/Institutional	3	2	3	2	2	1	2	18	2
Residential	0.05	0.06	0.1	0.06	0.05	0.05	1	0.007	2
Total, tons/year	59	3,300	3,050	260	110	5,500	6,700	330	710,000

	Cr	Co	Cu	F	Fe	Pb	Mn	Hg	Mo
Electric Generation	84	63	72	83	77	92	89	81	74
Industrial	11	23	16	13	20	7	10	14	16
Commercial/Institutional	5	14	12	2	3	1	1	3	10
Residential	0.1	0.3	0.07	2	0.2	0.05	0.5	2	0.05
Total, tons/year	1,800	510	2,800	37,000	170,000	1,300	5,100	59	692

	Ni	Se	Te	Tl	Sn	Ti	U	V	Zn	Zr
Electric Generation	60	85	90	90	75	89	86	63	89	78
Industrial	21	13	9	9	13	9	10	20	10	20
Commercial/Institutional	19	2	1	1	12	2	4	17	1	2
Residential	0.02	1	0.07	0.06	0.1	0.06	0.05	0.02	0.1	0.2
Total, tons/year	8,100	870	31	10	130	62,000	1,700	11,000	2,300	2,300

Table 5. TRACE ELEMENTS IN SOLID WASTE (ASH): PERCENT OF TOTAL GENERATED BY CONVENTIONAL STATIONARY COMBUSTION SYSTEM CATEGORIES

	Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
Electric Generation	80.7	88.9	83.2	83.1	84.3	84.6	0	82.6	0	75.1
Industrial	16.4	8.9	13.2	12.5	13.3	12.8	0	14.1	0	11.7
Commercial/Institutional	1.3	0.9	1.4	1.8	0.8	1.1	0	1.4	0	5.4
Residential	1.6	1.6	2.2	2.6	1.6	1.6	0	1.9	0	7.8
Total, tons/year	170	13,500	17,600	812	349	17,900	0	121	0	5,550

	Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni
Electric Generation	69.3	77.6	0	86.9	80.9	97.7	77.9	80.0	80.8
Industrial	8.9	12.1	0	8.8	14.6	1.2	20.2	13.0	12.0
Commercial/Institutional	8.2	4.1	0	1.8	1.8	0.6	1.8	2.6	2.9
Residential	13.7	6.2	0	2.5	2.6	0.4	0.1	4.6	4.3
Total, tons/year	2,120	4,720	0	1,510,000	2,790	13,800	7	1,280	5,180

	Se	Te	Tl	Sn	Ti	U	V	Zn	Zr
Electric Generation	76.0	83.7	83.4	76.1	83.1	84.5	83.6	82.6	85.5
Industrial	22.1	13.1	12.6	12.5	12.8	12.9	13.1	12.8	11.1
Commercial/Institutional	1.0	1.2	1.7	1.4	1.7	1.1	1.3	1.8	1.4
Residential	1.0	1.9	2.4	9.9	2.4	1.6	2.0	2.8	2.1
Total, tons/year	408	99	34	383	197,000	4,970	9,320	7,600	19,000

CONCLUSIONS

The following text highlights some of the major conclusions which we have drawn from the results of this study. In general, the conclusions and interpretations apply to national emission levels; on a local level, any of the combustion categories considered may present a serious environmental problem due to variations in fuel type, size, operating practices, weather patterns, geology, hydrology, and population density.

- Coal combustion is the largest contributor to the air, water, and solid waste burden generated by stationary combustion sources.
- The electric utility sector generates the largest percentage of most air, water, and solid waste pollutants. The large amount of fuel consumed by the utility sector, and specifically the very large amounts of coal burned, accounts for this pollutant production.
- Industrial steam generation, space heating, and stationary engine operation are less significant as pollutant sources than the electric utility sector. One reason is the extensive use of natural gas.
- Commercial/institutional and residential combustion systems are negligible contributors to the total burden of water and solid waste pollutants. They contribute negligible amounts of trace elements and only minor amounts of particulate, SO_x, and NO_x emissions to the environment. Coal-fired residential combustion systems are, however, the principal sources of organic emissions. Within the stationary combustion sources, residential systems are also a large source of hydrocarbon and carbon monoxide emissions.

The following discussion provides more extensive interpretations of the results of this study and specifically enumerates those areas which represent the major data gaps applicable to emissions from conventional stationary combustion systems. A number of general needs are presented first, followed by a listing of areas requiring further study which are specific to air and water emissions and to the generation of solid waste.

- On the basis of the preliminary emissions assessment completed in this program, it is apparent that a need exists for further development and analysis of the data base including: a compilation of critically reviewed and acceptable data; a means of storing and retrieving these data through the development of a computerized data handling system relating combustion systems and pollutants; and the development of software to evaluate the ramifications and significance of trends in fuel consumption and boiler design in order to adequately assess the environmental impact of stationary conventional combustion sources. The Source Test Data System (SOTDAT) could conceivably be used as a central depository for source test data and its subsequent analysis for air emissions, but some modification of the system is needed to insure adequate description of the source.

- Additional research should be conducted on combustion systems utilizing control practices and fuels that are representative of the existing situation or which can be expected to increase in prominence in the future. These investigations should follow the recommendations which are forthcoming from the priority ranking efforts currently being undertaken by Monsanto Research Corporation based on the data base compiled under this contract effort. This approach is important because numerous past programs, such as some dealing with trace element emissions to the air, have dealt with systems that are nonrepresentative of existing combustion sources and/or their control equipment.

- Greater effort should be expended to coordinate research activities within and between government agencies, industrial, academic and trade organizations to insure that appropriate personnel are cognizant of activities in the areas of combustion source emissions.

- Research directed to emissions of particulates, SO_x, NO_x, and trace elements should concentrate on coal combustion by electric utilities. Secondary efforts should be directed towards coal combustion by the industrial sector.

- The importance of trace element emissions from conventional stationary combustion systems cannot be precisely defined. Comparison of concentrations produced to industrial TLV's indicate that for most elements the concentrations produced are well below the TLV values and the emissions should not be particularly hazardous. However, a very large population is exposed and some trace elements produced by combustion tend to concentrate on the surface of fine particulates. In addition trace elements may catalyze atmospheric reactions. Investigations of trace element emissions should continue.

- Fine particulate and vapor phase emissions and control measures should be investigated with emphasis on coal combustion by electric utilities. Scrubber efficiencies should be determined for vapor phase trace elements and POM.

- Emission factors for polycyclic organic matter, halogens and SO_3 should be developed for all sectors because of the large uncertainties in the available data. Efforts should initially be concentrated on the residential sector as this sector produces most of the organics and may produce large amounts of SO_3. Coal combustion should receive major attention for POM. Oil combustion may contribute relatively high amounts of SO_3 and sulfuric acid due to the presence of vanadium catalysts.

- Efforts should be made to improve the efficiency of combustion of small residential and commercial burners to reduce emissions, particularly polycyclic organic emissions.

- Air emissions from flue gas desulfurization units should be evaluated for sulfates, fine particulates, and trace metals.

- Emission factors and control measures for NO_x emissions from stationary internal combustion engines should be further developed.

- Water emission research and development efforts should be directed primarily towards the electric utility sector with secondary efforts directed to the industrial sector. Efforts should also concentrate on coal combustion.

- A better definition of the electric utility and industrial sector water handling practices should be undertaken. Information in these areas has been difficult to obtain. Federal Power Commission data have been useful for the electric utility sector, but the data should be subjected to further analysis. Data on the practices of the industrial sector are particularly poor and should be improved. The National Pollution Discharge Elimination Permit System should be examined in detail as a potential source of additional information on both electric utility and industrial practices. State agencies may also be able to provide detailed data.

- Ash pond effluents should be characterized with regard to total and suspended solids, including composition of trace elements, organic, and organometallic compounds. Control methods should also be investigated.

- Cooling water practices and effluent concentrations in the industrial sector should be defined.

- The potential contribution of flue gas desulfurization processes to water emissions should continue to receive strong emphasis.

- Product recovery of coal ash (fly ash, bottom ash, and boiler slag) should be implemented to an increased extent.

- Ash handling practices of electric utilities and industrial combustion sources should be examined and the extent of control determined.

- The chemical composition (metals and organics) of coal and ash should be studied in more detail with greater emphasis on sampling and analytical procedures. In addition, although the amount of ash from residual oil is very small, the amount and composition should be investigated as no data are presently available.

- Methods for disposal of desulfurization wastes should be further investigated. Control measures, such as pond liners and stabilizers, should also be investigated.

REPORT ORGANIZATION

The emission summary tables contained in this report provide estimates of air, water, and solid waste emissions from the unit operations of combustion systems. While these tables may be found by referring to the Table of Contents, access to this data may be more readily obtained by the use of Table 6, Directory Of Major Tables Of Emissions.

For the most part, the data presented in the summary emission tables deal with national averages or ranges based on the best available information. While national figures cannot be related to individual plants, they do indicate the relative importance of various emission streams. The discussion accompanying the tables presents information on emissions, a review

Table 6. DIRECTORY OF MAJOR TABLES OF EMISSIONS

	Air pollutants				Water pollutants					Solid waste
	Stack emissions	Ash handling	Cooling	Fuel handling	Ash handling	Cooling	Fuel handling	Boiler blowdown	Other	Ash
	Table/page	Table/page	Table/page	Table/page	Table/page	Table/page	Table/page	Table/page	Table/page	Table/page
1.0.00.0.0 Electric Generation										
1.1.00.0.0 External Combustion	27/78	44/134	60/163	68/198	44/134 47/138 48/139	52/145	68/198 69/200	65/188	64/182 66/189 67/190	44/134
1.2.00.0.0 Internal Combustion	42/127	–	–	–	–	–	–	–	–	–
2.0.00.0.0 Industrial										
2.1.00.0.0 External Combustion	91/251	95/270	–	102/283	95/270	97/273	102/283	100/279	99/277 101/281	95/270
2.2.00.0.0 Internal Combustion	93/261	–	–	–	–	–	–	–	–	–
3.0.00.0.0 Commercial/Institutional										
3.1.00.0.0 External Combustion	116/305	121/318	–	122/319	121/318	–	122/319	–	–	121/318
3.2.00.0.0 Internal Combustion	119/314	–	–	–	–	–	–	–	–	–
4.0.00.0.0 Residential	126/325	–	–	–	–	–	–	–	–	–

of pertinent literature, analysis of the data presented in the literature, and conclusions and recommendations of a general nature based on these data.

This report first presents, in Section II, a description of emissions from the electric utility industry. The population of boilers in this classification is presented as a function of boiler size, firing method, and boiler type. Most of the information here was extracted from a Federal Power Commission (FPC) Form 67 data tape provided by the FPC, and supplemented by data from the National Emission Data System (NEDS) data file and other sources. Section II also presents a detailed discussion of the unit operations and processes associated with emissions and provides estimates of emissions from these processes in the form of summary tables with attendant discussions.

Sections III, IV, and V present information concerning industrial, commercial/institutional, and residential combustion sources used for steam generation and space heating. Industrial and commercial/institutional fuel consumption for stationary engines is also included. The discussions in these sections follow the same format used for the electric utility industry in Section II. Large industrial boilers are very similar to utility boilers, but certain unit operations are not applicable to the smaller combustion sources. In addition, these smaller sources generally do not employ waste treatment and emission control devices.

Section VI discusses trends in fuel consumption and boiler design and their anticipated effect on emissions. Finally, Section VII reviews on-going or planned activities associated with combustion sources and their pollutant streams. This information was developed from three principal sources: (1) a list of presently funded EPA programs; (2) a review of the technical literature including computerized literature searches conducted by the National Technical Information Service and the Smithsonian Science Information Exchange Service; and (3) by contact with organizations and individuals active in the combustion area.

Throughout the report, and in the Appendices, fuel consumption and fuel properties (e.g., ash content, chemical composition, etc.) have been provided by state and region. This breakdown will help to define the potential air, water, and solid waste emissions by location and combustion category. Situations where data are missing or of questionable value have been noted. A ranking scheme has been devised to indicate the quality of existing data from various emission streams.

PRIMARY DATA SOURCES

As noted previously, this emission assessment has been based on a survey of the available technical literature supplemented by contact with governmental, industrial and other information sources concerned with various aspects of emissions from conventional combustion sources. Contact has been made with individuals associated with the Environmental Protection Agency, the Federal Energy Administration, the Energy Research and Development Administration, the Bureau of Mines, the Federal Power Commission and other governmental agencies. Industrial trade groups such as the American Petroleum Institute, the Electric Power Research Institute, the American Boiler Manufacturers Association, the National Coal Association, and the National Ash Association have also been contacted. Finally, major government contractors have been utilized as sources of recent and current information. In our survey of available literature we have been assisted by the many individuals and associations enumerated above and by the use of literature searches conducted by such organizations as the National Technical Information Service and the Smithsonian Science Information Exchange Service. As anticipated, most of the pertinent literature concerning emissions emanates from the Environmental Protection Agency and other government agencies, although the larger industrial and trade organizations have also sponsored investigations of direct relevance to combustion system emissions. The primary sources of electric utility industry data are the Federal Power Commission and the National Emission Data System. NEDS is also a source of information for industrial and

and commercial/institutional combustion sources, although the coverage of these areas is relatively incomplete. Other data sources, the American Boiler Manufacturers Association, Bureau of Mines, and the Bureau of Census identify sales and fuel consumption figures which have proven to be useful in appraising practices in the nonutility area. Again, other industrial organizations, largely under EPA sponsorship, have analyzed the available data, and their contributions were useful in the compilation of this document.

The major data sources which were used in the preparation of this report are discussed below.

Federal Power Commission Data Files and Publications

A primary source for information on the electric utility industry is the Federal Power Commission (FPC). The report entitled, Steam-Electric Plant Air and Water Quality Control Data for the Year Ended December 31, 1972, published by the FPC in March 1975,[5] contains summary data on such subjects as fuel consumption, fuel quality, emissions, ash and sulfur collection and disposal, types of cooling, cooling water use, and chemical additive use (water). The data are presented by State and Air Quality Control Region or Water Resource Region, as well as 696 individual plants. The primary limitation of the summary document is the lack of individual boiler data. Capacity and/or fuel use associated with specific furnace types, firing patterns, boiler sizes, and boiler ages are not presented.

To supplement the above FPC publication we developed a program to survey FPC magnetic storage tapes containing FPC Form 67 information representing the year 1972. These forms (see Appendix A) were collected from individual electric generating plants throughout the United States whose cumulative fuel consumption was 97 percent of all combustion fuels used for electric generation. Although the information represents the best utility data available, errors exist in the tape, reflecting the inherent human error in both filling out the FPC Form 67 by the many utility personnel involved, and in translating this information to the magnetic tape. Time did not permit a more detailed examination of the tape and possible resolution of discrepancies. In general, it is felt that the information obtained from the FPC represents an accurate portrayal of the utility industry. Fuel consumption data for utilities were updated through information available from the FPC and the Bureau of Mines.

National Emission Data System

The National Emission Data System (NEDS) has on file extensive data on air pollution from electrical power generation via combustion. Data for individual plants in this file include boiler capacity and type, fuel characteristics and consumption, control equipment type and efficiency, stack parameters and emission estimates. The data are presented for different years from 1970 through 1973, depending on the state, but most data are from 1972 or 1973. The NEDS system is designed to include data on essentially all the significant oil-, coal-, and natural gas-fired electric generation units, especially sources with the potential to emit over 100 tons per year of any of the criteria pollutants. The plant size corresponding to this emission rate depends on the fuel type, operating hours, ash content, and sulfur content, but generally encompasses coal-fired plants larger than 4 MW. Because plants above 25 MW capacity generate all but a few percent of the electricity in the United States, the NEDS system should include data on all significant electric generation emissions sources. The quality of the NEDS data, however, varies from state to state and in some states it is lacking; for example, almost no data are available for New York. Access to NEDS files has been difficult because of computer problems, although NEDS has been utilized to provide information for anthracite-fired and lignite-fired boilers in this study. The NEDS system also contains some data for industrial and commercial sources. However, many of these sources are too small to be included in the NEDS data bank. Estimates from data in the 1972 National Emission Data Report[6] indicate that only 60 percent of the industrial fuel use and 20 percent of the commercial fuel use are included in the NEDS point source data bank. Individual studies conducted by other EPA contractors have provided much of the information used to compile estimates of boiler populations, operating characteristics, and emissions presented in this report for these nonutility categories.

Other Data Sources

Other data sources used in this study include articles in the technical journals and reports sponsored by governmental and industrial organizations. These articles and reports are too numerous to mention here, but are referenced through the report.

Air emissions have thus far received the most attention in the literature, although information concerning water and solid waste treatment is becoming increasingly available. Water and solid waste effluent streams are more difficult to analyze due to the large plant-to-plant variations in cooling water, ash handling, and water treatment practices. This variation is exhibited in the FPC data base dealing with such effluent streams.

The most comprehensive information on water and solid waste effluent is at present on file with the National Pollution Discharge Elimination System (NPDES). The wastewater pollutants specified in permit applications to this program include more pollutants than those specified in present proposed federal effluent guidelines for electric utilities. This NPDES data base is not fully computerized and is, therefore, difficult to survey. One attempt has been made, however, for the EPA Office of Water and Hazardous Materials where data have been assembled to varying degrees of completeness for specific waste stream effluents, based on a sampling of about 66 percent of all coal-fired utility plants.[4] This reference has been used extensively in this document.

The industrial, commercial/institutional, and residential sectors have received less attention in the technical literature than the electric utility area. Combustion units used in the former are smaller than those used by electric utilities although they are more numerous. Information on fuel consumption by industrial users for 1973 is available from the Bureau of Mines for each state. Commercial/institutional and residential fuel consumption data for some fuels also are available from the Bureau of Mines. The 1972 Census of Manufacturers provides data from which commercial and residential fuel use can be estimated. Again many EPA sponsored programs consider industrial, commercial and residential fuel combustion installations as well as electric generation facilities. Trade organizations, such as the National Oil Fuel Institute, have provided data on sales and system characteristics of small boilers and furnaces.

QUALITY OF EMISSION ESTIMATES

The extent and quality of the available data base generally decrease as one progresses from the electric utility sector to the residential sector. Although the data in the electric utility area are more extensive than the other categories, there are still significant data gaps especially with regard to water and solid waste pollutants. Moreover, very little is known about trace metal and organic air emissions from utility boilers, while data on criteria pollutant emissions exhibit appreciable variability. Differences in fuel; boiler load, design and age; control device performance and operating parameters; and other factors contribute to variations in air emissions data. Since not all of the factors contributing to emissions are well understood or definable, it is not possible to predict with accuracy the performance of individual boilers. While certain generalizations concerning emissions can and have been made (i.e., emission factors), extended sampling programs are required to adequately determine individual boiler emissions. National average data, if based on a suitably large and representative sampling of boilers, can, however, be used to define areas where additional R&D activity is needed.

The problem of relating national averages to individual plant performance is particularly difficult for water and solid waste pollutants due to the large variations in plant design and operating practices. The quantity and quality of available data are also less than that available for air emissions. With the exception of the limited amount of data available from the FPC for utilities, the data base is not centralized and compilation of the data will require an extensive effort. Detailed definition of the volume and composition of wastewater effluents and solid waste leachates is lacking. In the case of solid waste leachates, particularly, an appreciable time period may be required to determine their extent and impact. Moreover, the extent and the impact of water and solid waste pollutants will depend not only on plant practices (fuel, boiler type and size, etc.) but on local conditions such as soil properties, meteorology, land and water availability, etc.

Air and water quality and solid waste disposal regulations require that all new plants meet certain discharge requirements. Existing plants will also be required to meet state regulations and proposed Federal Performance Water Quality Standards as required by Public Law 92-500, the Water Pollution Control Act Amendments of 1972. As these regulations become effective, it will be possible to define regulated effluents for nonexempt sources in a more meaningful manner.

To provide a meaningful index of the realiability of the information presented, the following data quality factors have been assigned to each category of emissions:

Quality factor for emission estimates	Definition
A	Very good - highest confidence. Error probably 10 percent. Data well accepted and verified.
B	Good - Reputable and accepted. Error probably 25 percent.
C	Fair - Error probably 50 percent. Validity may be uncertain due to method of combining or applying data.
D	Poor - Low confidence in data. Error probably 100 percent. Validity questionable or uncertain due to method of combining data.
E	Very poor - Validity of data unknown or uncertain due to method of combining data. Error probably within or around an order of magnitude.

These data quality factors are evaluations based on the source of the data, the amount of data available, the accuracy of the measurements, and variations arising from differences in operating practices in different plants, regions, and industries.[7] They help to differentiate between results based on comprehensive field measurements and crude estimates based on limited data.

An emission estimate quality factor of A has been assigned to emissions of pollutants such as SO_2 where a high degree of correspondence between fuel sulfur content and SO_2 has been demonstrated for most fuel boilers and operating conditions. An exception is the high alkali content lignite fuels which retain variable amounts of sulfur in the ash. A quality factor of B has been assigned to emissions such as particulate and NO_x emissions from utility boilers, where the data base is reputable and extensive but subject to variation due to differences in boiler design, load, efficiency, age, estimates of control device efficiency and other factors. A factor of C reflects a more limited data base. Inadequate analytical methods or definition of operating practices and procedures may be the principal cause or contribute to this rating. Ratings of D or E were assigned for other reasons as well; for example, a quality factor of E has been assigned to trace element emissions. Although some of the recent data is of good or excellent quality, the amount of data is limited. The extension of this data to all plants to arrive at national estimates is questionable. Similarly a rating of E has also been assigned to organic emissions for a number of reasons: a lack of data; uncertainties in data due to analytical methods; an inadequate understanding of the ratio of vapor phase to particulate emissions; and inadequate coverage of combustion systems.

In order to assess the impact of reported emissions, regardless of data quality, frequency factors have been developed. These factors range from 0 to 1 with a value of 1 indicating a continuous emission stream. A value of 1 has been assigned, for example, to stack emissions from utility boilers whereas a factor of 0.003 has been assigned to utility equipment cleaning indicating that cleaning occurs once a year on the average. The factors are provided for use with the models now under development by Monsanto Research Corporation to assess the priority of the selected combustion systems. Table 7 presents our summary appraisal of the data quality and frequency factors for individual waste emission sources.

COMBUSTION SYSTEM CLASSIFICATION

In order to effectively organize the various combustion systems and report associated emissions, a classified index for combustion systems has been developed and is summarized in Table 8. The majority of tabular data presented in this report are arranged according to this classification system. It is anticipated that this system will assist in the future computerization of these data. Table 9 lists the combustion systems

Table 7. EMISSION ESTIMATE QUALITY AND FREQUENCY FACTORS

	Utilities	Industrial	Commercial/ Institutional	Residential
Fuel and boiler data				
Fuel consumption	A	B	B	B
Combustion unit population	A	D	D	D
Combustion unit characteristics	A	B	B	B
Control devices	A	C	NA[a]	NA
Emissions data				
Flue gas emissions				
Particulates	B(1.0)	C(0.8)	D(0.5)	C(0.4)
Fine particulates	D(1.0)	D(0.8)	D(0.5)	C(0.4)
SO_x	A(1.0)	A(0.8)	A(0.5)	A(0.4)
NO_x	B(1.0)	B(0.8)	C(0.5)	C(0.4)
HC	D(1.0)	D(0.8)	D(0.5)	D(0.4)
CO	B(1.0)	C(0.8)	C(0.5)	C(0.4)
PPOM	E(1.0)	E(0.8)	E(0.5)	E(0.4)
PHH	E(1.0)	E(0.8)	E(0.5)	E(0.4)
Trace elements	E(1.0)	E(0.8)	E(0.5)	E(0.4)
Internal combustion				
Air emissions	B(0.2)	B(0.25)	B(0.25)	NA
Ash handling				
Air emissions	E(1.0)	E(0.8)	NA	NA
Pond discharge				
Amount	B(1.0)	E(0.8)	NA	NA
Composition	E	E	NA	NA
Solid waste				
Amount	A(1.0)	B(0.8)	B(0.5)	B(0.4)
Composition, major elements	A	A	B	B
Composition, trace elements	E	E	E	E
Cooling systems				
Water discharge				
Volume	A(1.0)	E(0.8)	NA	NA
Composition	C	C	NA	NA
Thermal	A(1.0)	E(0.8)	NA	NA
Air emissions	C(1.0)	E(0.8)	NA	NA
Other wastewater sources				
Boiler water treatment				
Volume	D(1.0)	E(0.8)	NA	NA
Composition	C	D	NA	NA
Boiler blowdown				
Volume	E(0.5)	E(0.1)	NA	NA
Composition	D	E	NA	NA
Equipment cleaning				
Volume	D(0.003)	D(0.001)	NA	NA
Composition	C	C	NA	NA
Fuel handling				
Air emissions	E(1.0)	E(0.8)	E(0.5)	NA
Coal pile drainage				
Volume	C(0.2)	C(0.2)	C(0.2)	NA
Composition	C	C	C	NA

[a] NA - Not applicable.

Table 8. COMBUSTION SYSTEM CLASSIFICATION TABLE[a]

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10
Row	Function	Combustion	Fuel, 2-digit designation	Furnace type	Firing	Thermal rate, 10^6 Btu/hr	Fly ash reinjection	Particulate control	SO_2 control	NO_x control
0	All	All	00 All	All	All	All		All	All	All
1	Utilities: Electric generation	External	10 Coal: total 11 Coal: bituminous	Pulverized: dry bottom	Tangential	>5000	With	ESP	Limestone	Staged firing
2	Industrial	Internal: All	12 Coal: anthracite	Pulverized: wet bottom	All other than tangential	1500-5000	Without	ESP: dry	Lime	Low excess air
3	Commercial	Internal: Gas turbine	13 Coal: lignite	Cyclone	Front or back	500-1500		ESP: wet	Double alkali	Flue gas recirculation
4	Residential	Internal: Reciprocating	20 Petroleum: total 21 Residual oil	Stoker: All	Opposed	100-500		Cyclone: ESP	Magnesium	H_2O injection
5	Mixed function		22 Distillate oil	Stoker: overfeed	Vertical			Cyclone	Cat-Ox	Reduced air preheating
6			23 Crude oil 24 Kerosene 25 Diesel	Stoker: spreader		<100		Wet scrubber	Wellman-Lord	
7			26 Gasoline	Stoker: underfeed				Fabric filter	Citrate	
8			30 Gas: total 31 Natural 32 Process 33 LPG						Dry absorption	
9			40 Refuse: total 41 Bagasse 42 Wood/bark 43 Other					Other	Other	Other
x	None/other	None/other	None/other	None/other	None/other			None	None	None

[a] 1.1.10.2.1.3 Denotes an electric utility, external combustion, coal-fired, pulverized wet bottom, tangentially-fired boiler of 500-1500 MM Btu/hr capacity.

Table 9. SELECTED COMBUSTION SYSTEMS EMPHASIZED IN THIS PROGRAM

System No.[a]	Classification code	Combustion system
	1.0.00.0.0	Electric Generation
	1.1.00.0.0	External Combustion
	1.1.10.0.0	Coal
	1.1.11.0.0	Bituminous
1	1.1.11.1.0	Pulverized Dry
2	1.1.11.2.0	Pulverized Wet
3	1.1.11.3.0	Cyclone
4	1.1.11.4.0	All Stokers
	1.1.12.0.0	Anthracite
5	1.1.12.1.0	Pulverized Dry
6	1.1.12.4.0	All Stokers
	1.1.13.0.0	Lignite
7	1.1.13.1.0	Pulverized Dry
8	1.1.13.2.0	Pulverized Wet
9	1.1.13.3.0	Cyclone
10	1.1.13.4.0	All Stokers
	1.1.20.0.0	Petroleum
	1.1.21.0.0	Residual Oil
11	1.1.21.0.1	Tangential Firing
12	1.1.21.0.2	All Other
	1.1.22.0.0	Distillate Oil
13	1.1.22.0.1	Tangential Firing
14	1.1.22.0.2	All Other
	1.1.30.0.0	Gas
15	1.1.30.0.1	Tangential Firing
16	1.1.30.0.2	All Other
17	1.1.40.0.0	Refuse

[a] The systems numbered in this column will be used in the priority ranking study being conducted by Monsanto Research Corporation, Dayton, Ohio, under Contract No. 68-02-1404, Task Order No. 18.

Table 9 (continued). SELECTED COMBUSTION SYSTEMS EMPHASIZED IN THIS PROGRAM

System No.	Classification code	Combustion system
	1.2.00.0.0	Internal Combustion
	1.2.20.0.0	Petroleum
	1.2.30.0.0	Gas
	1.3.00.0.0	Internal Combustion/ Gas Turbine
	1.3.20.0.0	Petroleum
18	1.3.22.0.0	Distillate Oil
19	1.3.30.0.0	Gas
	1.4.00.0.0	Internal Combustion/ Reciprocating Engine
	1.4.20.0.0	Petroleum
20	1.4.22.0.0	Distillate Oil
21	1.4.30.0.0	Gas
	2.0.00.0.0	Industrial
	2.1.00.0.0	External Combustion
	2.1.10.0.0	Coal
	2.1.11.0.0	Bituminous
22	2.1.11.1.0	Pulverized Dry
23	2.1.11.2.0	Pulverized Wet
24	2.1.11.3.0	Cyclone
25	2.1.11.4.0	All Stokers
	2.1.12.0.0	Anthracite
26	2.1.12.4.0	All Stokers
	2.1.13.0.0	Lignite
27	2.1.13.6.0	Spreader Stokers
	2.1.20.0.0	Petroleum
	2.1.21.0.0	Residual Oil
28	2.1.21.0.1	Tangential Firing
29	2.1.21.0.2	All Other

Table 9 (continued). SELECTED COMBUSTION SYSTEMS EMPHASIZED IN THIS PROGRAM

System No.	Classification code	Combustion system
	2.1.22.0.0	Distillate Oil
30	2.1.22.0.1	Tangential Firing
31	2.1.22.0.2	All Other
	2.1.30.0.0	Gas
32	2.1.30.0.1	Tangential Firing
33	2.1.20.0.2	All Other
34	2.1.40.0.0	Waste
	2.2.00.0.0	Internal Combustion
	2.2.20.0.0	Petroleum
	2.2.30.0.0	Gas
	2.3.00.0.0	Internal Combustion/ Gas Turbine
	2.3.20.0.0	Petroleum
35	2.3.22.0.0	Distillate Oil
36	2.3.30.0.0	Gas
	2.4.00.0.0	Internal Combustion/ Reciprocating Engine
	2.4.20.0.0	Petroleum
37	2.4.22.0.0	Distillate Oil
38	2.4.30.0.0	Gas
	3.0.00.0.0	Commercial/Institutional
	3.1.00.0.0	External Combustion
	3.1.10.0.0	Coal
	3.1.11.0.0	Bituminous
39	3.1.11.1.0	Pulverized Dry
40	3.1.11.2.0	Pulverized Wet
41	3.1.11.4.0	All Stokers
	3.1.12.0.0	Anthracite
42	3.1.12.4.0	All Stokers

Table 9 (continued). SELECTED COMBUSTION SYSTEMS EMPHASIZED IN THIS PROGRAM

System No.	Classification code	Combustion system
	3.1.13.0.0	Lignite
	3.1.13.4.0	All Stokers
	3.1.20.0.0	Petroleum
	3.1.21.0.0	Residual Oil
43	3.1.21.0.1	Tangential Firing
44	3.1.21.0.2	All Other
	3.1.22.0.0	Distillate Oil
45	3.1.22.0.1	Tangential Firing
46	3.1.22.0.2	All Other
	3.1.30.0.0	Gas
47	3.1.30.0.1	Tangential Firing
48	3.1.30.0.2	All Other
	3.1.40.0.0	Refuse
	3.2.00.0.0	Internal Combustion
49	3.2.20.0.0	Petroleum
50	3.2.30.0.0	Gas
	4.0.00.0.0	Residential
	4.1.00.0.0	External Combustion
	4.1.10.0.0	Coal
51	4.1.11.0.0	Bituminous
52	4.1.12.0.0	Anthracite
53	4.1.13.0.0	Lignite
	4.1.20.0.0	Petroleum
54	4.1.22.0.0	Distillate Oil
55	4.1.30.0.0	Gas
	4.1.40.0.0	Refuse
56	4.1.42.0.0	Wood

which have been selected for emphasis in this program. These systems will be subsequently assigned priorities utilizing the emission estimates provided in subsequent sections of the report and priority analyses being conducted by Monsanto Research Corporation.

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SECTION II

UTILITIES: ELECTRIC GENERATION

Most of the electric power generated in the United States is produced in steam plants using fossil fuels and high speed turbines. In 1974 these plants delivered on the average 1 kilowatt-hour of electricity for 10,400 Btu supplied by the fuel. The modern electric utility boiler operates at pressures of 2,500 to 4,000 psi, and delivers superheated steam (with waterwall tubes, superheating and heat recovery accessories) at a temperature of 1,000°F or higher.

Electric utilities must provide service on demand. Because system load varies with time, significant portions of system capacity are unused much of the time. External combustion systems (i.e., fossil fuel boilers) provide most of the base and intermediate load capacity. Base units operate almost continually with an annual load factor of about 80 percent with shutdown resulting only for maintenance, refueling and repairs. Intermediate load requirements are usually met by older, less efficient fossil fuel units.

Peak load facilities must be capable of rapid startup and shutdown. This type of service is most suitable for internal combustion systems; i.e., gas turbines. However, while internal combustion systems represent about 20 percent of capacity they account for only about 4 percent of the electric utility energy production.

Electric generation plants are designed to meet the specific needs of the utility in the most economical fashion. The cost of electricity will depend principally on the capital equipment, fuel, and operating and maintenance costs. Because the cost of the fuel consumed throughout the life of a generating plant is a significant part of the generating cost, the availability and price of the fuel and the unit efficiency of the plant are of paramount importance in the selection of plant equipment. Coal, despite its many drawbacks, is more often used by utilities than the other two fossil fuels, oil and natural gas, because of its general abundance and low cost. Therefore, for reasons of economics, there is a trend to boilers of larger sizes since the efficiency increases, while the unit investment and other costs decrease, as the size increases. For this reason, in the case of coal-fired units, the older, smaller stoker furnaces have been largely replaced by larger pulverized coal or cyclone furnaces. Both the pulverized and cyclone furnaces can burn almost any type of coal. While the cyclone furnace is most suitable for the combustion of the lower grade subbituminous and lignite coals, its use in new plants will be virtually eliminated because its NO_x emissions exceed those specified by New Source Performance Standards (NSPS).

The combustion of coal is more difficult than the combustion of other fossil fuels. Its use involves equipment for: handling, size reduction, ash disposal, dust control, and sootblowing. Coal combustion accounts for the major portion of air, water, and solid waste emissions from the electric utility industry.

Natural gas is the easiest fuel to burn and eliminates the need for fuel storage, ash handling, sootblowing, and particulate and SO_2 control equipment. Oil has many of the desirable characteristics of natural gas. However, high sulfur, sodium, and vanadium content oils require provision for removal of deposits by water washing of heat transfer surfaces and sootblowing. Emission control equipment may also be required for some units and fuel oils, due to NSPS and other more stringent regulations.

Other fuels are used to only a minor extent by the electric utility industry. The burning of municipal refuse as a supplement to coal, although highly publicized, is now being practiced at only one utility, the Union Electric Meramac Plant in St. Louis County. This source produced less than 0.01 percent of the total electrical energy generated in the United States in 1974. Bagasse and wood are utilized in certain parts of the country by industry to produce both steam and electricity, principally for on-site use.

This section on utilities combustion is divided into 10 major subsections. The following subsection is an overview of the industry which provides information on the size of various facilities, the types of fuels used and the consumption rates of these fuels. The next subsection discusses external and internal combustion units and includes information on the number and characteristics of these units. Unit operations or processes which are sources of emissions to air, water, and land are defined in the third subsection and emissions from specific unit operations including stack emissions, ash handling emissions, cooling system water wastes, other wastewater emissions, fuel storage and handling emissions and flue gas desulfurization wastes are discussed in the next subsections.

SIZE OF INDUSTRY, SOURCES OF ENERGY, FUEL CONSUMPTION

Approximately 1,900 x 10^6 MWh of electrical energy was generated in the United States during 1974,[1,2] of which approximately 1,800 x 10^6 MWh, or 95 percent, was generated by utilities for general consumption. Industrial on-site production of electricity (see Section III) has remained stable at approximately 100 x 10^6 MWh per year since 1965.[1,2]

Fossil fuel, nuclear fuel, and hydropower are the primary energy sources used to produce electricity. During 1974, fossil fuels produced 79 percent of the total electricity generated, while hydropower and nuclear fuel produced 15 percent and 6 percent, respectively.[1] Seventy-seven percent of installed generation capacity was driven by steam prime movers; 9 percent by internal combustion, and 14 percent by hydropower. Refuse is also burned in small amounts to produce electricity[3] and is considered later in this section of the report.

Fossil fuel consumption for electricity production increased 5 to 9 percent per year in the period 1968 to 1973 with a total increase to 43 percent.[2,4] However, from 1973 to 1974 fossil fueled electric production decreased 3.5 percent, due primarily to the sharp increase in energy costs, energy conservation efforts, the recession, and also as a result of increased production from nuclear fuel and hydropower.[5] Table 10 indicates that over the past 7 years coal has been the predominant fossil fuel. Oil's share of the electric utility market has more than doubled since 1968, from 9 to 22 percent while both coal and gas have decreased slightly.

Table 10. UTILITY FOSSIL-FUELED ELECTRICITY PRODUCTION - SOURCE OF ENERGY
(percent)[a]

	Year						
Fuel	1968[b]	1969[b]	1970[b]	1971[c]	1972[c]	1973[c]	1974[c]
Coal	63	60	56	53	53	55	55
Oil	9	12	14	18	21	22	22
Gas	28	28	29	29	27	23	23

[a] Totals may not add due to rounding.

[b] References 2 and 4.

[c] See Table 11.

In 1974, 54 percent of the fossil fuel consumed was bituminous coal, 0.25 percent anthracite, 1.3 percent lignite, 23 percent natural gas, 19 percent residual oil, and 2.9 percent distillate oil. The bituminous coal category includes 10 to 15 percent subbituminous coal.[6] Included in the natural gas category are less than 0.6 percent "combined" coke oven gas, refinery gas, and blast furnace gas. The use of liquified natural gas and synthetic natural gas was essentially zero. All heavy oils were included in the residual oil category and consisted of 0.6 percent No. 4, 1.5 percent No. 5, 95.5 percent No. 6, and 2.4 percent crude.[6] Distillate oil consisted primarily of No. 2 fuel oil, and less than 10 percent kerosene and jet fuel. Approximately 96 percent of the consumed fuels were burned in external combustion systems and 4 percent in internal combustion systems. A small undetermined amount of fuel was burned in combined cycle plants consisting of gas turbines followed by waste heat boilers.

External combustion systems (boilers) produced 1419 x 10^6 MWh of electricity in 1974 from an installed capacity of 337,000 MW for an unusually low yearly average load factor of 48 percent. In previous years the load factor was 50 to 55 percent. Comparison of the fuel consumed to the electricity produced yields a 1974 heat rate of 10,420 Btu/kWh,* equivalent to a heat-to-electricity efficiency of 33 percent.

Internal combustion systems consist of gas turbines and reciprocating engines burning distillate oil and natural gas. A few gas turbines are designed to burn residual and/or crude oil after pretreatment[7] but no such fuel use was reported for 1974.[6] Fuel used by internal combustion systems was only 3.8 percent of the electric utility total and consisted of almost equal amounts of distillate oil and natural gas. Gas turbines consumed seven times as much fuel as reciprocating engines. The predominant turbine fuel was distillate oil while the predominant reciprocating engine fuel was natural gas. Internal combustion systems are used primarily for peaking, emergency, and reserve power, and therefore had a low yearly average load factor of only 10 percent during 1974. Their heat rate of 14,750 Btu/kWh is higher than that of external combustion systems; they are operated at an average efficiency of only 23 percent.

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*Heat rate is a term used in the utility industry to identify the amount of heat (Btu) consumed in the generation of 1 kilowatt-hour of electricity. The heat rate for a 100 percent efficient system would be 3,413 Btu/kWh. However, 100 percent efficiency is theoretically impossible. Theoretical ultimate efficiency of a thermal power plant (the Carnot efficiency) operating with 1050°F steam (the current maximum steam temperature) and 60°F cooling water is 66 percent.[12]

During 1974, the Union Electric Meramac Plant in St. Louis County was the only utility burning refuse to produce electricity.[3] Its capacity was 12.5 tons per hour[8] and if operated at a 50 percent yearly load factor produced about 0.066×10^6 MWh of electricity.

Table 11 summarizes fuel consumption and generation capacities of all types of combustion-based electric utilities for the years 1971 through 1974. This table was developed primarily from FPC data presented in weekly issues of the Federal Power Commission News.[5,6,10] Additional data sources were used to determine system capacities for the 1971 to 1973 period[2,4] and for 1974.[11] The generating capacity of external combustion systems by fuel type was estimated by assuming that capacity was proportional to the electricity produced. This is equivalent to assuming that each system had the same yearly load factor. The electricity generated by external combustion systems was calculated from heat rate data (Btu/kWh) for each fuel.[13] The fuel consumed, system capacity, and electricity generated by internal combustion systems were available directly from FPC data,[10,21] and estimates of capacity by fuel type were made in the manner discussed in Table 11.

Fuel consumption data by state and system type are presented in detail in Appendix B. Figure 1 shows the geographic distribution of utility fuel consumption. Most of the fuel (75 percent) is consumed in the eastern half of the United States with Texas (8.4 percent) and California (6.0 percent) also consuming large quantities. Electric utility coal consumption is presented in Figure 2. Coal consumption is concentrated in the eight-state region of Michigan, Illinois, Indiana, Ohio, Pennsylvania,

Table 11. FOSSIL-FUELED ELECTRIC UTILITY - CAPACITY, FUEL CONSUMPTION, AND PRODUCTION, 1971 - 1974

		Year	Capacity, MW	Fuel consumed,[a] 10^{12} Btu	Electricity generated, 10^6 MWh
1.0.00.	Electric generation	1974	380,000[b]	15,387[d]	1459.0[b]
		1973	356,000[c]	15,928[d]	1520.0[d]
		1972	322,000[c]	14,968[d]	1411.0[d]
		1971	297,600[c]	13,872[d]	1305.0[d]
1.1.00.	External combustion	1974	337,000[b]	14,798[d]	1419.0[d]
		1973	318,000[c]	15,396[d]	1468.0[d]
		1972	294,000[c]	14,439[d]	1375.0[d]
		1971	275,600[c]	13,458[d]	1277.0[d]
1.1.10.	External combustion; coal	1974	198,300[e]	8,502[d]	835.0[f]
		1973	184,500[e]	8,668[d]	851.0[f]
		1972	163,400[e]	7,830[d]	769.0[f]
		1971	152,700[e]	7,299[d]	712.0[g]
1.1.11.	External combustion; bituminous	1974	192,600[e]	8,264[h]	812.0[t]
		1973	178,900[e]	8,450[i]	830.0[t]
		1972	159,700[e]	7,657[i]	752.0[t]
		1971	149,700[e]	7,161[i]	698.0[t]
1.1.12.	External combustion; anthracite	1974	880[e]	38[j]	3.7[t]
		1973	780[e]	37[j]	3.6[t]
		1972	830[e]	40[j]	3.9[t]
		1971	880[e]	42[j]	4.1[t]
1.1.13.	External combustion; lignite	1974	4,670[e]	200[k]	19.7[t]
		1973	3,840[e]	181[k]	17.8[t]
		1972	2,780[e]	133[k]	13.1[t]
		1971	2,020[e]	96[k]	9.4[t]

Table 11 (continued). FOSSIL-FUELED ELECTRIC UTILITY - CAPACITY, FUEL CONSUMPTION, AND PRODUCTION, 1971 - 1974

		Year	Capacity, MW	Fuel consumed,[a] 10^{12} Btu	Electricity generated, 10^6 MWh
1.1.20.	External combustion; petroleum	1974	66,700[e]	3,039[d]	281.0[m]
		1974	65,300[e]	3,285[d]	303.0[m]
		1972	54,200[e]	2,758[d]	255.0[m]
		1971	46,300[e]	2,321[d]	216.0[n]
1.1.21.	External combustion; residual oil	1974	63,600[e]	2,901[h]	268.0[t]
		1973	62,500[e]	3,139[l]	290.0[t]
		1972	52,700[e]	2,682[l]	248.0[t]
		1971	45,700[e]	2,291[l]	213.0[t]
1.1.22.	External combustion; distillate oil	1974	3,010[e]	138[h]	12.7[t]
		1973	2,890[e]	146[l]	13.4[t]
		1972	1,490[e]	76[l]	7.0[t]
		1971	580[e]	30[l]	2.7[t]
1.1.30.	External combustion; gas	1974	72,000[e]	3,257[h]	305.0[o]
		1973	69,200[e]	3,443[l]	321.0[o]
		1972	76,500[e]	3,851[l]	350.0[o]
		1971	76,600[e]	3,868[l]	357.0[p]
1.2.00.	Internal combustion; all fuels	1974	43,300[b]	589[h]	39.6[q]
		1973	37,800[l]	532[l]	35.7[m]
		1972	32,700[l]	529[l]	36.2[m]
		1971	26,500[l]	413[l]	28.4[m]
1.3.00.	Gas turbines; all fuels	1974	38,300[l]	515[h]	33.4[q]
		1973	32,900[l]	458[l]	29.5[l]
		1972	27,900[l]	452[l]	29.5[l]
		1971	21,800[l]	340[l]	22.1[l]

Table 11 (continued). FOSSIL-FUELED ELECTRIC UTILITY - CAPACITY, FUEL CONSUMPTION, AND PRODUCTION, 1971 - 1974

	Year	Capacity, MW	Fuel consumed,[a] 10^{12} Btu	Electricity generated, 10^{6} MWh
1.3.20. Gas turbines; oil fueled	1974	21,400[s]	286[h]	18.7[t]
	1973	18,400[s]	254[l]	17.5[t]
	1972	17,600[s]	283[l]	18.6[t]
	1971	11,300[s]	175[l]	11.5[t]
1.3.30. Gas turbines; gas fueled	1974	16,900[s]	229[h]	14.7[t]
	1973	14,500[s]	204[l]	13.0[t]
	1972	10,300[s]	169[l]	10.9[t]
	1971	10,500[s]	165[l]	10.6[t]
1.4.00. Reciprocating engines; all fuels	1974	4,960[b]	74[r]	6.2[r]
	1973	4,910[l]	74[l]	6.2[l]
	1972	4,800[l]	77[l]	6.7[l]
	1971	4,670[l]	73[l]	6.3[l]
1.4.20. Reciprocating engines; oil fueled	1974	1,780[u]	26[r]	2.2[t]
	1973	1,760[u]	26[l]	2.2[t]
	1972	1,940[u]	31[l]	2.7[t]
	1971	1,690[u]	36[l]	2.3[t]
1.4.30. Reciprocating engines; gas fueled	1974	3,180[u]	48[r]	4.0[t]
	1973	3,150[u]	48[l]	4.0[t]
	1972	2,860[u]	46[l]	4.0[t]
	1971	2,980[u]	47[l]	4.0[t]

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[a] Equivalent consumption of individual fuels in units of mass or volume may be calculated from the following heating values:

Bituminous coal - 22.4 x 10^6 Btu/ton, 1971-1973[13]
21.9 x 10^6 Btu/ton, 1974[5]

Anthracite coal - 26.0 x 10^6 Btu/ton[9]

Lignite coal - 16.0 x 10^6 Btu/ton[9]

Residual oil - 147,000 Btu/gal[14]

Distillate oil - 140,000 Btu/gal[9]

Natural gas - 1,022 Btu/ft^3 [5,9]

[b] Reference 11.

[c] References 15 and 16.

[d] Data represent the sum of the subcategories and agree with data in references 1, 2, 4, 5, 6, and 10.

[e] The capacity of systems associated with any particular fuel is variable as evidenced by past coal-to-oil conversions and the present oil-to-coal conversions.[17] In addition, many plants burn both natural gas and oil. The external combustion system capacity associated with each fuel was assumed to be proportional to the electricity generated.

[f] Calculated from the coal used and an average heat rate of 10,176 Btu/kWh.[13]

[g] Calculated from the coal used and an average heat rate of 10,252 Btu/kWh.[13]

[h] Reference 6.

[i] References 4 and 18.

[j] References 6 and 19.

[k] References 18 and 20.

[l] References 10 and 21.

[m] Calculated from the oil used and an average heat rate of 10,826 Btu/kWh.[13]

[n] Calculated from the oil used and an average heat rate of 10,884 Btu/kWh.[13]

[o] Calculated from the gas used and an average heat rate of 10,847 Btu/kWh.[13]

Table 11 (continued). FOSSIL-FUELED ELECTRIC UTILITY - CAPACITY, FUEL CONSUMPTION, AND PRODUCTION, 1971 - 1974

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[p] Calculated from the gas used and an average heat rate of 10,733 Btu/kWh.[13]

[q] The 1974 heat rate was assumed to be the same as 1973.

[r] 1974 data in reference 6 did not provide a breakdown of internal combustion systems between turbines and reciprocating engines. The capacity of reciprocating engines was essentially the same during 1973 and 1974 so it was assumed that they used the same amount of fuel. The remainder was assigned to the turbine category.

[s] Turbine capacity by fuel type was assumed to be proportional to the amount of fuel used although many turbines burn both oil and gas.

[t] Electricity generated by fuel type was assumed to be proportional to the fuel used; i.e., within certain fuel groups the efficiency is not affected by fuel type.

[u] Reciprocating engine capacity by fuel type was assumed to be proportional to the fuel used.

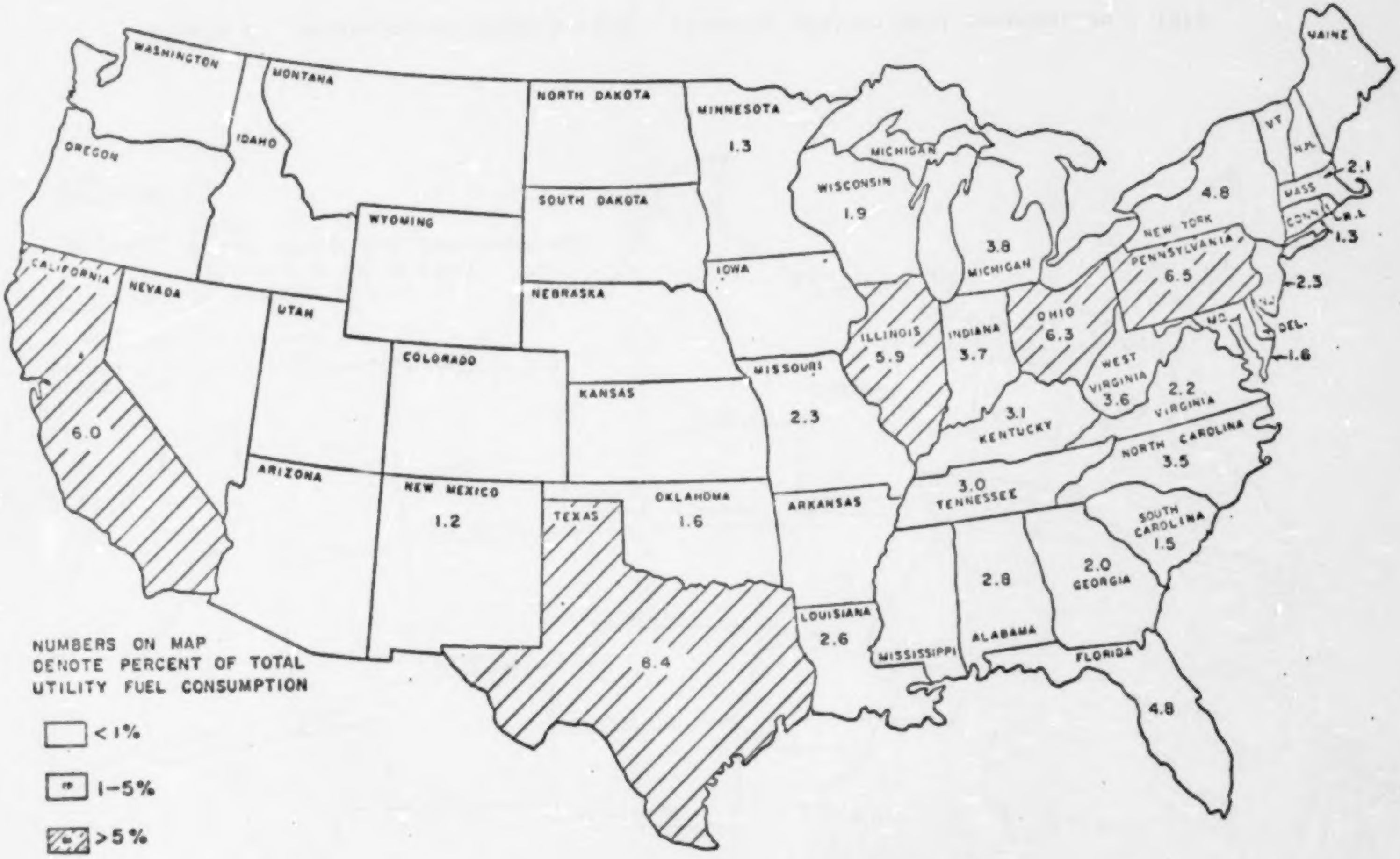
WASHINGTON
MONTANA
NORTH DAKOTA
MINNESOTA
1.3
MAINE
OREGON
IDAHO
MICHIGAN
WISCONSIN
1.9
VT
N.H.
2.1
SOUTH DAKOTA
WYOMING
4.8
MASS
CONN
R.I.
1.3
NEW YORK
3.8
MICHIGAN
PENNSYLVANIA
6.5
CALIFORNIA
NEVADA
IOWA
NEBRASKA
UTAH
2.3
ILLINOIS
5.9
INDIANA
3.7
OHIO
6.3
MD.
DEL.
1.6
COLORADO
MISSOURI
2.3
WEST VIRGINIA
3.6
2.2
VIRGINIA
KANSAS
6.0
3.1
KENTUCKY
NORTH CAROLINA
3.5
ARIZONA
NEW MEXICO
1.2
TEXAS
OKLAHOMA
1.6
ARKANSAS
3.0
TENNESSEE
SOUTH CAROLINA
1.5
2.8
2.0
GEORGIA
LOUISIANA
2.6
MISSISSIPPI
ALABAMA
FLORIDA
8.4
4.8
NUMBERS ON MAP DENOTE PERCENT OF TOTAL UTILITY FUEL CONSUMPTION
< 1%
1–5%
> 5%

Figure 1. Geographical distribution - electric utility fuel consumption - 1973

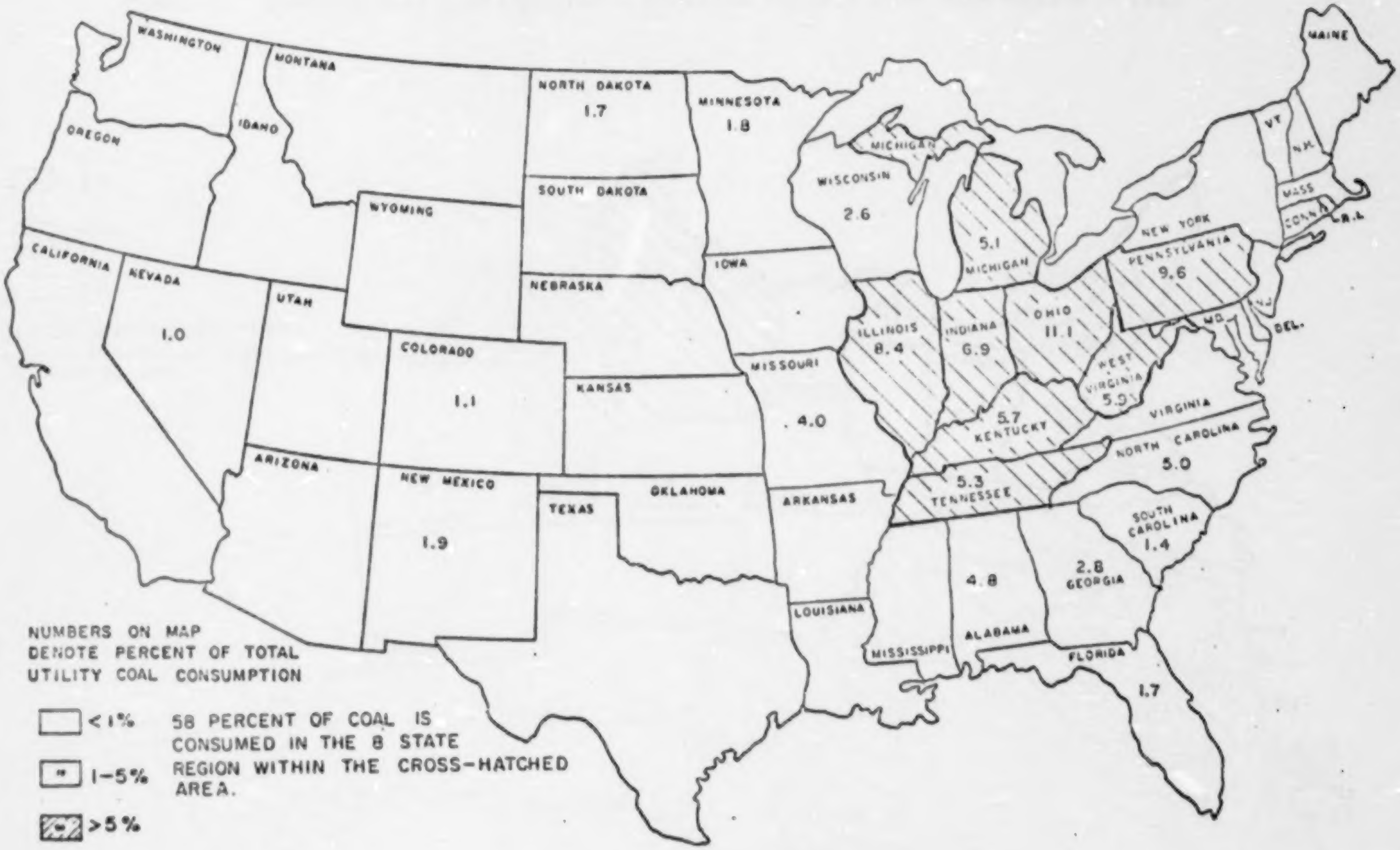
WASHINGTON
MONTANA
NORTH DAKOTA
1.7
MINNESOTA
1.8
MAINE
OREGON
IDAHO
MICHIGAN
VT
N.H.
WISCONSIN
2.6
MASS
SOUTH DAKOTA
WYOMING
CONN
R.I.
NEW YORK
5.1
MICHIGAN
PENNSYLVANIA
9.6
CALIFORNIA
NEVADA
IOWA
NEBRASKA
UTAH
1.0
ILLINOIS
8.4
INDIANA
6.9
OHIO
11.1
N.J.
MD.
DEL.
COLORADO
MISSOURI
WEST VIRGINIA
5.9
KANSAS
1.1
5.7
KENTUCKY
VIRGINIA
4.0
NORTH CAROLINA
5.0
ARIZONA
NEW MEXICO
OKLAHOMA
ARKANSAS
5.3
TENNESSEE
TEXAS
1.9
SOUTH CAROLINA
1.4
4.8
2.8
GEORGIA
LOUISIANA
ALABAMA
MISSISSIPPI
FLORIDA
1.7
NUMBERS ON MAP
DENOTE PERCENT OF TOTAL
UTILITY COAL CONSUMPTION
<1%
1-5%
>5%
58 PERCENT OF COAL IS
CONSUMED IN THE 8 STATE
REGION WITHIN THE CROSS-HATCHED
AREA.

Figure 2. Geographical distribution - electric utility coal consumption - 1973

Kentucky, West Virginia, and Tennessee, where 58 percent of the coal is consumed. Oil consumption (see Appendix B) is concentrated in states along the eastern seaboard including the New England, Middle Atlantic and South Atlantic regions where a total of 72 percent of the oil is consumed. Fifty-three percent of the gas is consumed in the West South Central Region (Arkansas, Louisiana, Oklahoma, and Texas).

POPULATION AND CHARACTERISTICS OF COMBUSTION EQUIPMENT

The boiler classifications included in the emission summary tables, and their associated fuel use, are presented in Table 12. The data in this table were derived from the previously discussed fuel use data and from boiler population and characteristics described in detail in the following subsections. Boiler population and characteristics were based primarily on computer surveys developed by GCA of individual boiler data reported to the Federal Power Commission and stored on magnetic tape, (Form FPC-67 is presented in Appendix A). All steam-electric plants of 25 MW or greater capacity, which used 97 percent of the fuel consumed by steam-electric plants, were required to complete Form FPC-67.[22,23] The data gathered from these forms were the most recent and comprehensive on utility boilers. FPC data for 1973 should be available late in 1975.

The following four subsections briefly describe coal-, oil- and gas-, and solid waste-fired boilers, and internal combustion engines. Data are presented on furnace type, firing pattern, size, and fly ash reinjection practices. In addition, methods and data sources used to develop the detailed boiler characteristics are discussed.

Coal-Fired Boilers

A detailed description of coal-fired boilers for the year 1972 is presented in Table 13, based on computer surveys developed by GCA of individual boiler data reported to the Federal Power Commission on Form FPC-67

Table 12. ELECTRIC UTILITY FUEL CONSUMPTION, 1974

Classification system number	Combustion system category	10^{12} Btu[a]
1.0.00.0.0	Electric Generation	15,387
1.1.00.0.0	External Combustion	14,798
1.1.10.0.0	Coal	8,502
1.1.11.0.0	Bituminous	8,264
1.1.11.1.0	Pulverized Dry	5,971
1.1.11.2.0	Pulverized Wet	1,118
1.1.11.3.0	Cyclone	1,118
1.1.11.4.0	All Stokers	57
1.1.12.0.0	Anthracite	38
1.1.12.1.0	Pulverized Dry	13
1.1.12.2.0	Pulverized Wet	0
1.1.12.3.0	Cyclone	0
1.1.12.4.0	All Stokers	25
1.1.13.0.0	Lignite	200
1.1.13.1.0	Pulverized Dry	120
1.1.13.2.0	Pulverized Wet	30
1.1.13.3.0	Cyclone	30
1.1.13.4.0	All Stokers	20
1.1.20.0.0	Petroleum	3,039
1.1.21.0.0	Residual Oil	2,901
1.1.21.0.1	Tangential Firing	1,128
1.1.21.0.2	All Other	1,773
1.1.22.0.0	Distillate Oil	138
1.1.22.0.1	Tangential Firing	54
1.1.22.0.2	All Other	84
1.1.30.0.0	Gas	3,257
1.1.30.0.1	Tangential Firing	791
1.1.30.0.2	All Other	2,466
1.1.40.1.1	Refuse	0.6
1.2.00.0.0	Internal Combustion	589
1.3.00.0.0	Turbine	515
1.3.20.0.0	Petroleum	286
1.3.30.0.0	Gas	229
1.4.00.0.0	Reciprocating	74
1.4.20.0.0	Petroleum	26
1.4.30.0.0	Gas	48

[a] Conversion factors from Btu to other units are presented in Appendix F.

Table 13. COAL-FIRED ELECTRIC UTILITY BOILERS - 1972[a]

	Number of boilers	Capacity		Coal burned		Load factor[c]	Design heat rate, Btu/kW[d]	Capacity average age,[c] years
		10^3 ton coal/hr	MW	10^3 ton/yr	10^{12} Btu/yr[b]			
1.1.10.0.0 Coal	1,082	60.26	139,420	314,220	7,039	59.5	9,670	12
1.1.10.1.0.0.0 Pulverized dry	594	38.93	91,480	207,140	4,640	60.7	9,540	10
1.1.10.1.1.0.0 Tangential	234	20.89	49,630	109,840	7,460	60.0	9,430	9
1.1.10.1.1.0.1 With fly ash reinjection	0	0	0	0	0	0	0	0
1.1.10.1.1.0.2 Without fly ash reinjection	234	20.89	49,630	109,840	2,460	60.0	9,430	9
1.1.10.1.1.1.2 >5000 10^6 Btu/hr[f]	20	6.44	12,840	21,300	427	37.8[e]	11,230[e]	1
1.1.10.1.1.2.2 1500-5000	84	9.46	24,380	58,170	1,303	70.2	8,700	9
1.1.10.1.1.3.2 500-1500	105	4.55	11,230	28,500	638	71.5	8,420	18
1.1.10.1.1.4.2 <500	25	0.44	910	1,870	42	48.6	10,830	28
1.1.10.1.3.0.0 Front	306	10.95	23,330	61,450	1,376	64.0	10,600	16
1.1.10.1.3.0.1 With fly ash reinjection	1	0.23	680	1,530	34	75.2	7,650	2
1.1.10.1.3.1.1 >5000 10^6 Btu/hr	1	0.23	680	1,530	34	75.2	7,650	2
1.1.10.1.3.2.1 1500-5000	0	0	0	0	0	0	0	0
1.1.10.1.3.3.1 500-1500	0	0	0	0	0	0	0	0
1.1.10.1.3.4.1 <500	0	0	0	0	0	0	0	0
1.1.10.1.3.0.2 Without fly ash reinjection	305	10.72	22,650	59,920	1,342	63.8	10,600	16
1.1.10.1.3.1.2 >5000 10^6 Btu/hr	3	0.79	1,920	4,850	109	70.5	9,170	4
1.1.10.1.3.2.2 1500-5000	32	2.84	6,920	18,210	408	73.3	9,180	9
1.1.10.1.3.3.2 500-1500	121	5.06	10,420	30,190	676	68.1	10,880	19
1.1.10.1.3.4.2 <500	149	2.04	3,390	6,670	149	37.4	13,450	30
1.1.10.1.4.0.0 Opposed	54	7.02	18,790	35,850	870	58.3	8,370	5
1.1.10.1.4.0.1 With fly ash reinjection	1	0.23	680	590	13	29.0	7,650	1
1.1.10.1.4.1.1 >5000 10^6 Btu/hr	1	0.23	680	590	13	29.0	7,650	1
1.1.10.1.4.2.1 1500-5000	0	0	0	0	0	0	0	0
1.1.10.1.4.3.1 500-1500	0	0	0	0	0	0	0	0
1.1.10.1.4.4.1 <500	0	0	0	0	0	0	0	0
1.1.10.1.4.0.2 Without fly ash reinjection	53	6.86	18,110	35,260	790	58.7	8,490	5
1.1.10.1.4.1.2 >5000 10^6 Btu/hr	14	3.87	10,370	18,700	419	55.2	8,360	1
1.1.10.1.4.2.2 1500-5000	19	2.61	6,890	15,020	336	65.7	8,490	6
1.1.10.1.4.3.2 500-1500	2	0.14	360	900	20	73.4	9,000	14
1.1.10.1.4.4.2 <500	18	0.24	490	640	14	30.9	10,820	41
1.1.10.2.0.0.0 Pulverized wet	175	8.34	20,750	38,810	869	53.1	9,000	13
1.1.10.2.1.0.0 Tangential	31	2.60	7,140	13,520	303	59.4	8,150	6

Table 13 (continued). COAL-FIRED ELECTRIC UTILITY BOILERS - 1972[a]

		Number of boilers	Capacity		Coal burned		Load factor[c]	Design heat rate, Btu/kW[d]	Capacity average age,[c] years
			10^3 ton coal/hr	MW	10^3 ton/yr	10^{12} Btu/yr[b]			
1.1.10.2.1.0.1	With fly ash reinjection	2	0.02	30	90	2	46.0	16,670	31
1.1.10.2.1.1.1	>5000 10^6 Btu/hr	0	0	0	0	0	0	0	0
1.1.10.2.1.2.1	1500-5000	0	0	0	0	0	0	0	0
1.1.10.2.1.3.1	500-1500	0	0	0	0	0	0	0	0
1.1.10.2.1.4.1	<500	2	0.02	30	90	2	46.0	16,670	31
1.1.10.2.1.0.2	Without fly ash reinjection	29	2.58	7,110	13,430	301	59.5	8,120	6
1.1.10.2.1.1.2	>5000 10^6 Btu/hr	6	1.58	4,520	6,930	155	50.2	7,810	2
1.1.10.2.1.2.2	1500-5000	5	0.48	1,310	2,780	62	65.8[e]	8,240	9
1.1.10.2.1.3.2	500-1500	9	0.35	880	2,520	56	82.6	8,860	15
1.1.10.2.1.4.2	<500	9	0.17	400	1,200	27	80.7	9,500	19
1.1.10.2.3.0.0	Front	125	4.13	9,320	18,420	413	51.0	9,910	21
1.1.10.2.3.0.1	With fly ash reinjection	0	0	0	0	0	0	0	0
1.1.10.2.3.0.2	Without fly ash reinjection	125	4.13	9,320	18,420	413	51.0	9,910	21
1.1.10.2.3.1.2	>5000 10^6 Btu/hr	0	0	0	0	0	0	0	0
1.1.10.2.3.2.2	1500-5000	16	1.53	3,800	9,620	215	71.9	9,000	14
1.1.10.2.3.3.2	500-1500	50	1.72	3,270	7,340	164	48.8	11,770	22
1.1.10.2.3.4.2	<500	59	0.88	2,250	1,460	33	19.0	8,760[e]	32
1.1.10.2.4.0.0	Opposed	19	1.61	4,290	6,870	154	48.7	8,410	5
1.1.10.2.4.0.1	With fly ash reinjection	3	0.42	1,100	930	21	25.0	8,640	4
1.1.10.2.4.1.1	>5000 10^6 Btu/hr	0	0	0	0	0	0	0	0
1.1.10.2.4.2.1	1500-5000	3	0.42	1,100	930	21	25.0	8,640	4
1.1.10.2.4.3.1	500-1500	0	0	0	0	0	0	0	0
1.1.10.2.4.4.1	<500	0	0	0	0	0	0	0	0
1.1.10.2.4.0.2	Without fly ash reinjection	16	1.19	3,190	5,940	133	57.1	8,340	6
1.1.10.2.4.1.2	>5000 10^6 Btu/hr	0	0	0	0	0	0	0	0
1.1.10.2.4.2.2	1500-5000	9	1.09	3,100	5,750	133	60.0	7,900	4
1.1.10.2.4.3.2	500-1500	1	0.03	46	100	2	36.5	15,220	20
1.1.10.2.4.4.2	<500	6	0.06	44	90	2	16.4	31,820	33
1.1.10.3.x.0.0	Cyclone	68	7.33	16,620	39,090	875	60.8	9,880	8
1.1.10.3.0.0.1	With fly ash reinjection	21	2.36	5,540	12,650	283	61.1	9,550	8
1.1.10.3.0.1.1	>5000 10^6 Btu/hr	3	0.84	1,940	3,290	74	44.5	9,740	3
1.1.10.3.0.2.1	1500-5000	11	1.17	2,890	6,360	142	62.3	9,030	9
1.1.10.3.0.3.1	500-1500	7	0.35	710	3,000	61	97.1[e]	11,130	15
1.1.10.3.0.4.1	<500	0	0	0	0	0	0	0	0

Table 13 (continued). COAL-FIRED ELECTRIC UTILITY BOILERS - 1972[a]

		Number of boilers	Capacity		Coal burned		Load factor[c]	Design heat rate, Btu/kW[d]	Capacity average age,[c] years
			10^3 ton coal/hr	MW	10^3 ton/yr	10^{12} Btu/yr[b]			
1.1.10.3.0.0.2	Without fly ash reinjection	47	4.97	11,080	26,440	592	60.7	10,050	8
1.1.10.3.0.1.2	>5000 10^6 Btu/hr	6	1.80	3,720	10,200	228	64.9	10,810	5
1.1.10.3.0.2.2	1500-5000	17	2.26	5,640	11,790	264	59.6	8,970	6
1.1.10.3.0.3.2	500-1500	19	0.83	1,640	4,110	92	56.8	11,280	16
1.1.10.3.0.4.2	<500	5	0.09	50	340	8	43.5	25,000	20
1.1.10.4.0.0.0	All stokers	189	2.13	2,750	3,500	78	18.8	17,310	37
1.1.10.4.0.1.0	>5000 10^6 Btu/hr	0	0	0	0	0	0	0	0
1.1.10.4.0.2.0	1500-5000	1	0.07	80	410	9	69.9	18,750	9
1.1.10.4.0.3.0	500-1500	11	0.44	570	240	5	6.3		44
1.1.10.4.0.4.0	<500	177	1.62	2,100	2,850	63	20.1	17,290	38
1.x.xx.x.x.x.x	Other	56	3.54	7,850	25,680	575	82.8	10,100	14

[a] Based on 1972 FPC data, Form 67, which includes 97 percent of the utility industry.

[b] Based on an average heating value of 22.4×10^6 Btu/ton.

[c] Calculated data points. Capacity average age $\frac{\Sigma\ (\text{Capacity x age})}{\Sigma\ \text{Capacity}}$

[d] Calculated from the capacity data.

[e] Data points of doubtful validity.

[f] Size is based on maximum fuel input rate.

and stored on magnetic tape. The totals reported in Table 13 are within the ranges reported by other sources.[13,24,25]

The total number of coal-fired utility boilers, in the FPC data, was 1082 compared to 1500 reported to be in the National Emission Data System (NEDS) file.[24] The difference in the number of boilers may be due to the fact that NEDS includes boilers of a lower size limit, and that nonutility electric generation boilers are also included in the NEDS system. The average load factor of 59.5 percent is slightly higher than the utility industry average of 52 percent for 1972.[25] During 1972 the reported coal-fired utility boiler heat rate was 10,176 Btu per kWh,[13] compared to the GCA calculated design heat rate of 9670 Btu per kWh based on FPC data. The capacity average age[*] of coal-fired utility boilers at the end of 1972 was calculated to be 12 years.

While the data totals in Table 13 compare favorably with other data sources, as previously discussed, a few individual points appear to be questionable. For example, the load factor of 97.1 percent for the category 1.1.30.3.0.3.1 is unreasonable. These problems arise from difficulties encountered in processing the FPC magnetic tape because data had been coded in inconsistent formats. For instance, some boilers were reported as groups (2A/2B), and capacity was reported in different formats (500, 300/200, 250 each) from plant to plant. Time constraints did not permit all the above situations to be interpreted manually or by computer processing. Generally the results are considered to provide an accurate and detailed picture of the utility industry as it existed in 1972.

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[*] Capacity average age = Σ (capacity x age)/Σ capacity.

The boiler data presented in Table 13 are summarized by major subcategories in Table 14. The unknown category in the latter table contains boiler types that did not fit the FPC categories (for instance, pulverized vertically-fired) as well as boiler types that were miscoded. Data from the "unknown" category were apportioned to the other boiler types to obtain the final figures presented in Table 14. Almost 70 percent of the capacity consisted of pulverized dry bottom boilers, about 16 percent were pulverized wet, and 13 percent were cyclone boilers. Stoker-fired boilers comprised a large segment of the boilers by number (18 percent) but only a small segment by capacity (2.2 percent). In addition, stoker-fired boilers were very old with an average age of 37 years compared to the overall average boiler age of 12 years. Boilers above 5,000 x 10^6 Btu/hr. were very new (2 years old), and compared to the number of boilers (5.2 percent) burned a large fraction of the fuel (23 percent).

Pulverized coal-fired boilers burned 85 percent of the coal consumed by the electric utilities. Pulverized coal is burned by vertical, tangential, front or back and opposed firing. Few utility boilers use vertical firing.[24] Data in Table 13 show that 50 percent of the pulverized coal-fired boiler capacity used tangential firing, and 32 percent used front firing. Only 18 percent used opposed firing but these were the largest and newest boilers and represent a design trend. As shown in Table 15, only 1.3 percent of these boilers (by capacity) used fly ash reinjection.

The boiler distribution presented in Tables 13, 14, and 15 is for all coal-fired boilers. Anthracite coal is most commonly burned in industrial and commercial boilers with stationary or traveling grates.[9] Anthracite is not burned in spreader stokers because of its high ignition temperature. It may be burned as pulverized coal, although because of ignition problems,[9] this practice is limited to only a few plants in eastern Pennsylvania. Boilers burning anthracite are all dry bottom due to the very high ash softening temperature, commonly above 2,900°F.[27] We estimate

Table 14. SUMMARY: COAL-FIRED UTILITY BOILERS - 1972[a]

	Number of boilers, percent of total	Capacity, percent of total	Coal burned, percent of total	Capacity average age, years[b]
Boiler type				
Pulverized dry	57.8	69.5	71.8	10
Pulverized wet	17.2	15.8	13.5	13
Cyclone	6.6	12.6	13.5	8
Stoker	18.4	2.2	1.2	37
Boiler size, 10^6 Btu/hr				
>5000	5.2	27.5	23.2	2
1500-5000	19.2	38.8	44.6	8
500-1500	31.8	23.8	27.1	19
<500	43.9	9.9	5.0	33

[a] Summary of data in Table 13.

[b] Capacity average age = $\frac{\Sigma \text{ (Capacity x age)}}{\Sigma \text{ Capacity}}$.

Table 15. SUMMARY: PULVERIZED COAL-FIRED UTILITY BOILERS - 1972[a]

	Number of boilers, percent of total	Capacity, percent of total	Coal burned, percent of total	Capacity average age, years[b]
Fly ash reinjection				
With	9	1.3	1.3	4
Without	91	98.7	98.7	10
Firing pattern				
Tangential	34.5	49.8	50.2	8
Front	56.0	31.9	32.5	15
Opposed	9.5	18.3	17.4	4

[a] Summary of data in Table 13.

[b] Capacity average age = $\frac{\Sigma\ (\text{Capacity x age})}{\Sigma\ \text{Capacity}}$.

that anthracite boilers are 65 percent stokers and 35 pulverized dry based on a recent count of NEDS data.

Lignite is burned in all boiler types. Although in the past lignite was burned in small stokers, there has been a recent shift to large pulverized and cyclone type boilers.[28] We were able to identify most of the large boilers burning lignite through available FPC data[13,23] and estimated a distribution of 60 percent pulverized dry, 15 percent pulverized wet, 15 percent cyclone and 10 percent stokers.

Bituminous coal-fired boiler characteristics were determined from the overall coal-fired boiler characteristics by subtracting the lignite and anthracite boiler characteristics. As expected, the characteristics of bituminous coal-fired boilers were similar to all coal-fired boilers, since bituminous coal represents 97 percent of the coal burned. The following is the calculated bituminous coal-fired boiler distribution:

Furnace type		Percent of bituminous coal burned
1.1.11.1.0	Pulverized dry	72.3
1.1.11.2.0	Pulverized wet	13.5
1.1.11.3.0	Cyclone	13.5
1.1.11.4.0	All Stokers	0.7

Oil- and Gas-Fired Boilers

A similar analysis of the FPC magnetic tape was performed for oil- and gas-fired utility boilers. Boilers were classified as oil-fired if greater than 85 percent of the fuel was oil; gas-fired if greater than 85 percent of the fuel was gas; and if neither of the above conditions applied, the boiler was classified as dual-fired. The results are presented in Tables 16, 17, and 18, and represent 72 percent of the oil consumed at

Table 16. OIL-FIRED ELECTRIC UTILITY BOILERS - 1972[a]

		Approximate number of boilers	Fuel consumed, 10^{12} Btu/yr				Capacity average age,[c] years
			Oil	Coal	Gas	Total	
1.1.20.0.0.0	Petroleum[b]	537	1365.4	1.2	16.2	1382.8	14
1.1.20.0.1.0	Tangential	98	651.5	0.9	11.1	663.5	10
1.1.20.0.1.1	>5000 10^6 Btu/hr	4	85.5	0.0	9.8	86.3	4
1.1.20.0.1.2	1500-5000	24	262.8	0.0	6.8	296.6	5
1.1.20.0.1.3	500-1500	64	298.3	0.9	3.0	302.2	17
1.1.20.0.1.4	<500	6	4.9	0.0	0.5	5.4	18
1.1.20.0.2.0	All others[d]	439	713.9	0.3	5.1	719.3	13
1.1.20.0.3.0	Front or back	393	546.2	0.2	4.5	550.9	20
1.1.20.0.3.1	>5000 10^6 Btu/hr	1	9.2	0.0	0.0	9.2	1
1.1.20.0.3.2	500-5000	12	98.7	0.0	0.0	98.7	20
1.1.20.0.3.3	500-1500	84	268.8	0.2	3.5	272.5	20
1.1.20.0.3.4	<500	198	169.5	0.0	1.0	170.5	24
1.1.20.0.4.0	Opposed	16	111.8	0.0	0.3	112.1	4
1.1.20.0.4.1	>5000 10^6 Btu/hr	0	0.0	0.0	0.0	0.0	
1.1.20.0.4.2	1500-5000	10	99.7	0.0	0.0	99.7	3
1.1.20.0.4.3	500-1500	1	4.4	0.0	0.0	4.4	2
1.1.20.0.4.4	<500	5	7.7	0.0	0.3	8.0	19
1.1.20.0.9.0	Other	30	55.9	0.1	0.3	56.3	12
1.1.20.0.9.1	>5000 10^6 Btu/hr	0	0.0	0.0	0.0	0.0	
1.1.20.0.9.2	1500-5000	3	28.5	0.0	0.0	28.5	4
1.1.20.0.9.3	500-1500	5	11.9	0.0	0.0	11.9	29
1.1.20.0.9.4	<500	22	15.5	0.1	0.3	15.8	23

[a] Based on a GCA summary of data reported to the FPC on Form 67. GCA defined oil-fired boilers as those boilers that derived greater than 85 percent of their heat input from oil.

[b] This table does not include all oil as some is burned in gas-fired boilers, dual-fired boilers and some is not included on FPC Form 67.

[c] Capacity average age = $\frac{\Sigma\ (\text{Capacity} \times \text{age})}{\Sigma\ \text{Capacity}}$.

[d] All boilers not tangentially-fired.

Table 17. GAS-FIRED ELECTRIC UTILITY BOILERS - 1972[a]

		Approximate number of boilers	Fuel consumed, 10^{12} Btu/yr				Capacity average age,[c] years
			Oil	Coal	Gas	Total	
1.1.30.0.0.0	Gas[b]	560	54.3	4.9	2495.0	2554.2	9
1.1.30.0.1.0	Tangential	76	9.2	2.2	620.2	631.6	7
1.1.30.0.1.1	>5000 10^6 Btu/hr	8	0.0	0.0	83.3	83.3	1
1.1.30.0.1.2	1500-5000	34	3.8	0.0	330.5	334.3	5
1.1.30.0.1.3	500-1500	30	5.0	2.2	196.8	204.0	14
1.1.30.0.1.4	<500	4	0.4	0.0	9.6	10.0	15
1.1.30.0.2.0	All others[d]	484	45.1	2.7	1844.8	1922.6	10
1.1.30.0.3.0	Front or back	420	31.1	2.2	1138.7	1172.0	13
1.1.30.0.3.1	>5000 10^6 Btu/hr	2	0.0	0.0	69.6	69.6	3
1.1.30.0.3.2	500-5000	41	10.5	0.0	391.8	402.3	1
1.1.30.0.3.3	500-1500	154	13.1	1.5	447.6	462.2	17
1.1.30.0.3.4	<500	223	7.5	0.7	229.7	237.9	26
1.1.30.0.4.0	Opposed	56	14.0	0.2	718.8	733.0	5
1.1.30.0.4.1	>5000 10^6 Btu/hr	9	0.4	0.0	82.6	83.0	2
1.1.30.0.4.2	1500-5000	33	8.2	0.0	533.7	541.9	5
1.1.30.0.4.3	500-1500	8	0.4	0.0	19.9	20.3	12
1.1.30.0.4.4	<500	6	5.0	0.2	82.6	87.8	17
1.1.30.0.9.0	Other	8	0.0	0.3	17.3	17.6	19
1.1.30.0.9.1	>5000 10^6 Btu/hr	0	0.0	0.0	0.0	0.0	
1.1.30.0.9.2	1500-5000	0	0.0	0.0	0.0	0.0	
1.1.30.0.9.3	500-1500	4	0.0	0.3	16.4	16.7	20
1.1.30.0.9.4	<500	4	0.0	0.0	0.9	0.9	8

[a] Based on a GCA summary of data reported to the FPC on Form 67. GCA defined gas-fired boilers as those boilers that derived greater than 85 percent of their heat input from gas.

[b] This table does not include all gas as some is burned in oil-fired boilers, dual-fired boilers and some is not included on FPC Form 67.

[c] Capacity average age = $\frac{\Sigma \text{ (Capacity x age)}}{\Sigma \text{ Capacity}}$.

[d] All boilers not tangentially-fired.

Table 18. DUAL-FIRED ELECTRIC UTILITY BOILERS - 1972[a]

		Approximate number of boilers	Fuel consumed, 10^{12} Btu/yr				Capacity average age,[c] years
			Oil	Coal	Gas	Total	
1.1.xx.0.0.0	Dual-fired[b]	270	537.2	128.8	685.8	1351.8	13
1.1.xx.0.1.0	Tangential	37	99.7	43.5	144.8	288.0	8
1.1.xx.0.1.1	>5000 10^6 Btu/hr	3	17.9	0.0	49.3	67.2	1
1.1.xx.0.1.2	1500-5000	3	20.6	0.0	14.8	35.4	5
1.1.xx.0.1.3	500-1500	26	61.2	40.4	78.9	180.5	17
1.1.xx.0.1.4	<500	5	0.0	3.1	1.8	4.9	22
1.1.xx.0.2.0	All others[d]	233	437.5	85.3	541.0	1063.8	14
1.1.xx.0.3.0	Front or back	182	340.5	56.0	352.6	749.1	16
1.1.xx.0.3.1	>5000 10^6 Btu/hr	0	0.0	0.0	0.0	0.0	
1.1.xx.0.3.2	500-5000	26	239.5	0.0	176.3	415.8	10
1.1.xx.0.3.3	500-1500	58	67.0	17.0	119.7	203.7	19
1.1.xx.0.3.4	<500	98	34.0	39.0	56.6	129.6	27
1.1.xx.0.4.0	Opposed	33	90.5	2.5	164.1	257.1	6
1.1.xx.0.4.1	>5000 10^6 Btu/hr	3	18.9	0.0	39.0	157.9	1
1.1.xx.0.4.2	1500-5000	9	61.9	0.0	101.1	163.0	5
1.1.xx.0.4.3	500-1500	18	6.7	2.5	14.8	24.0	34
1.1.xx.0.4.4	<500	3	3.0	0.0	9.2	12.2	31
1.1.xx.0.9.0	Other	18	6.5	26.8	24.3	57.6	19
1.1.xx.0.9.1	>5000 10^6 Btu/hr	0	0.0	0.0	0.0	0.0	
1.1.xx.0.9.2	1500-5000	0	0.0	0.0	0.0	0.0	
1.1.xx.0.9.3	500-1500	13	6.1	24.3	23.4	53.8	19
1.1.xx.0.9.4	<500	5	0.4	2.5	0.9	3.8	13

[a] Based on a GCA summary of data reported to the FPC on Form 67. GCA defined dual-fired boilers as those boilers that derived less than 85 percent of their heat input from a single fuel.

[b] This table does not include fuel burned in boilers classified as coal-, oil-, or gas-fired.

[c] Capacity average age = $\frac{\Sigma \text{ (Capacity x age)}}{\Sigma \text{ Capacity}}$.

[d] All boilers not tangentially-fired.

steam-electric plants and 83 percent of the gas consumed. Therefore, the tables should be representative of the utility industry with the exception that possibly a large number of small boilers are not included.

The data in Tables 16, 17, and 18 show that about 70 percent of the oil burned in steam-electric boilers was burned in boilers classified as oil-fired, while most of the remaining was burned in dual-fired boilers. There was a large difference in ages of oil-fired boilers between the less than 500 x 10^6 Btu/hr groups and each of the other larger size groups. Oil-fired boilers below 500 x 10^6 Btu/hr had an average age of 28 years while larger boilers had an average age of 14 years. Boilers using opposed firing, although burning only a small fraction of the total oil, were the newest oil-fired boilers. Table 13 previously indicated that the newest coal-fired boilers also use opposed firing.

Table 19 is a summary of the relative amounts of oil burned by firing pattern and capacity and includes gas- and dual-fired boilers as well as oil-fired boilers. The table shows that 39 percent of the oil is burned in tangentially-fired boilers, and 47 percent is burned in front- or back-fired boilers. The table also shows that 80 percent of the oil is burned in boilers in the size range 500 to 5,000 x 10^6 Btu/hr. In the generation of the emission summary tables we assumed that distillate and residual oil-fired boilers had the same characteristics.

The boiler sizes and firing methods used for burning gas are similar to those burning oil. The newest boilers are the largest boilers and in general use opposed firing. Table 20 is a summary of the relative amounts of gas burned by firing pattern and capacity and includes oil- and dual-fired boilers as well as gas-fired boilers. The table shows that 24 percent of the gas is burned in tangentially-fired boilers and 47 percent in front- or back-fired boilers. The largest amount of gas (49 percent) is burned in the 1,500 to 5,000 x 10^6 Btu/hr size range.

Table 19. SUMMARY: UTILITY EXTERNAL COMBUSTION: OIL - DISTRIBUTION OF FIRING PATTERNS AND CAPACITIES, %

Firing pattern		
1.1.20.0.0.0	Petroleum	100.0
1.1.20.0.1.0	Tangential	38.9
1.1.20.0.2.0	All other (except tangential)	61.1
1.1.20.0.3.0	Front or back	46.8
1.1.20.0.4.0	Opposed	11.1
1.1.20.0.9.0	Other	3.2
Size		
1.1.20.0.0.0	Petroleum	100.0
1.1.20.0.0.1	>5000 10^6 Btu/hr	6.7
1.1.20.0.0.2	1500-5000	42.6
1.1.20.0.0.3	500-1500	38.0
1.1.20.0.0.4	<500	12.7

Table 20. SUMMARY: UTILITY EXTERNAL COMBUSTION: GAS - DISTRIBUTION OF FIRING PATTERNS AND CAPACITIES, %

Firing pattern		
1.1.30.0.0.0	Gas	100.0
1.1.30.0.1.0	Tangential	24.3
1.1.30.0.2.0	All other (except tangential)	75.7
1.1.30.0.3.0	Front or back	46.8
1.1.30.0.4.0	Opposed	27.6
1.1.30.0.9.0	Other	1.3
Size		
1.1.30.0.0.0	Gas	100.0
1.1.30.0.0.1	>5000 10^6 Btu/hr	10.5
1.1.30.0.0.2	1500-5000	48.6
1.1.30.0.0.3	500 x 1500	28.9
1.1.30.0.0.4	<500	12.0

Solid Waste-Fired Boilers

The primary solid waste fuels are bagasse, wood bark and municipal refuse. Bagasse, a sugar cane waste material, is used in Hawaii, Florida and Louisiana to produce steam and electricity, primarily for on-site use. Some electricity produced by bagasse may be sold to electric utilities,[29] however there are no known utility boilers burning bagasse. Similarly wood bark wastes are also used to generate electricity for on-site use in the lumber and paper industries, however, there are no utility users of wood bark in the Northwest[30] and no known utility users in other parts of the country.[*]

The only utility now burning refuse is the Union Electric Meramac Plant in St. Louis County. Currently Union Electric has the capability to use refuse for 10 percent of the fuel requirement in a 125 MW (≈1250 Btu/hr) boiler.[8] The boiler is a pulverized coal tangentially-fired unit with an electrostatic precipitator to control particulate emissions.[8] The refuse is air classified and metals are removed before it is fired at a rate of 12.5 tons/hour.[8] At a 50 percent load factor (typical of the utility industry) Union Electric would only burn 0.5×10^{12} Btu/year of refuse. Therefore, at the present time refuse represents an insignificant part of the total utility energy requirement of $15,400 \times 10^{12}$ Btu/year. Union Electric is expanding its refuse combustion capability to 8000 tons/day (all the recoverable refuse generated in the St. Louis area)[31] and therefore refuse combustion by the utility sector may be more significant in the future. Full utilization of solid waste (both municipal and agricultural) could supplement the national energy supply by 1.5 to 6 percent.[32] Further discussion of refuse combustion is presented later in this section of the report.

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[*] See Section III for a discussion of bagasse and waste bark/wood combustion.

Internal Combustion

Internal combustion engines are usually grouped into two classes: gas turbines and reciprocating engines. They are used extensively in the United States for peaking, emergency, and reserve electric generation. Some smaller electric utilities use gas turbines for base load also. The average yearly load factor is about 10 percent for internal combustion engines used in electric generation. Fuel use by internal combustion engines is only about 4 percent of the electric utility total.

The basic gas turbine consists of a compressor, a combustor and a turbine. The compressor supplies air at high pressure to the combustor. Fuel is mixed with the air in the combustor and burned. The combustion products are then expanded through the turbine to drive a rotor and generate electricity. A variety of advanced models have evolved from the simple gas turbine, and are classified into three general types of operating cycles: simple open cycle, regenerative open cycle, and combined cycle. In the simple open cycle the hot gas discharged from the turbine is exhausted to the atmosphere. In the regenerative open cycle the gas discharged from the turbine is passed through a heat exchanger to preheat the combustion air. Preheating the air increases the efficiency of the turbine, but also increases the amount of nitrogen oxides formed in the combustor. In the combined cycle the gas discharged from the turbine is used as auxiliary heat for a steam cycle. The combined cycle system offers a great increase in the combined efficiency of the overall system.[33]

Gas turbines can use a variety of fuels, but the fuel used cannot form ash or contain dust or uninhibited vanadium which erode the turbine blades.[34] A few gas turbines are designed to burn treated residual oil[20] but no such fuel use was reported in 1974.[6] Gas turbines used 286×10^{12} Btu oil and 229×10^{12} Btu gas in 1974.[5]

The FPC has compiled detailed data on gas turbines that consumed 90 percent of the gas turbine fuel in 1972. Based on these data the average plant size of 299 plants was 82 MW (1230 x 10^6 Btu/hr). There were 989 units with an average capacity of 27 MW (405 x 10^6 Btu/hr).[35] The average gas turbine heat rate was 15,400 Btu/kWh corresponding to an efficiency of 22 percent.[6]

Reciprocating engines fall into two main types, four-cycle and two-cycle. They may be further classified as spark engines, which use a spark plug to ignite the air-fired mixture, and diesel engines, in which the air is compressed until it reaches the ignition point of the injected fuel. In the reciprocating engines the fuel is combusted in a cylinder closed by a piston. The expanding combustion gases push against the piston, which transfers the motion to a rotating shaft. The fuels used in reciprocating engines include primarily distillate oil (26 x 10^{12} Btu/yr) and natural gas (48 x 10^{12} Btu/yr). The average reciprocating engine heat rate is 12,000 Btu/kWh corresponding to an efficiency of 29 percent.[6]

EMISSION SOURCES AND UNIT OPERATIONS

A large number of processes (or unit operations) utilized in the generation of steam and/or electricity generate emissions in the form of air, water, or solid waste pollutants. The typical operations and emission sources in a coal-fired electric power plant are presented in Figure 3. A coal-fired power plant involves the most unit processes and emission points, therefore many of the processes and emission points in Figure 3 are not applicable to gas- or oil-fired boilers and most are not applicable to internal combustion engines. The waste streams emanating from the individual unit process sources depicted in Figure 3 have been combined and are treated in this report in accordance with the unit operations presented in Table 21.

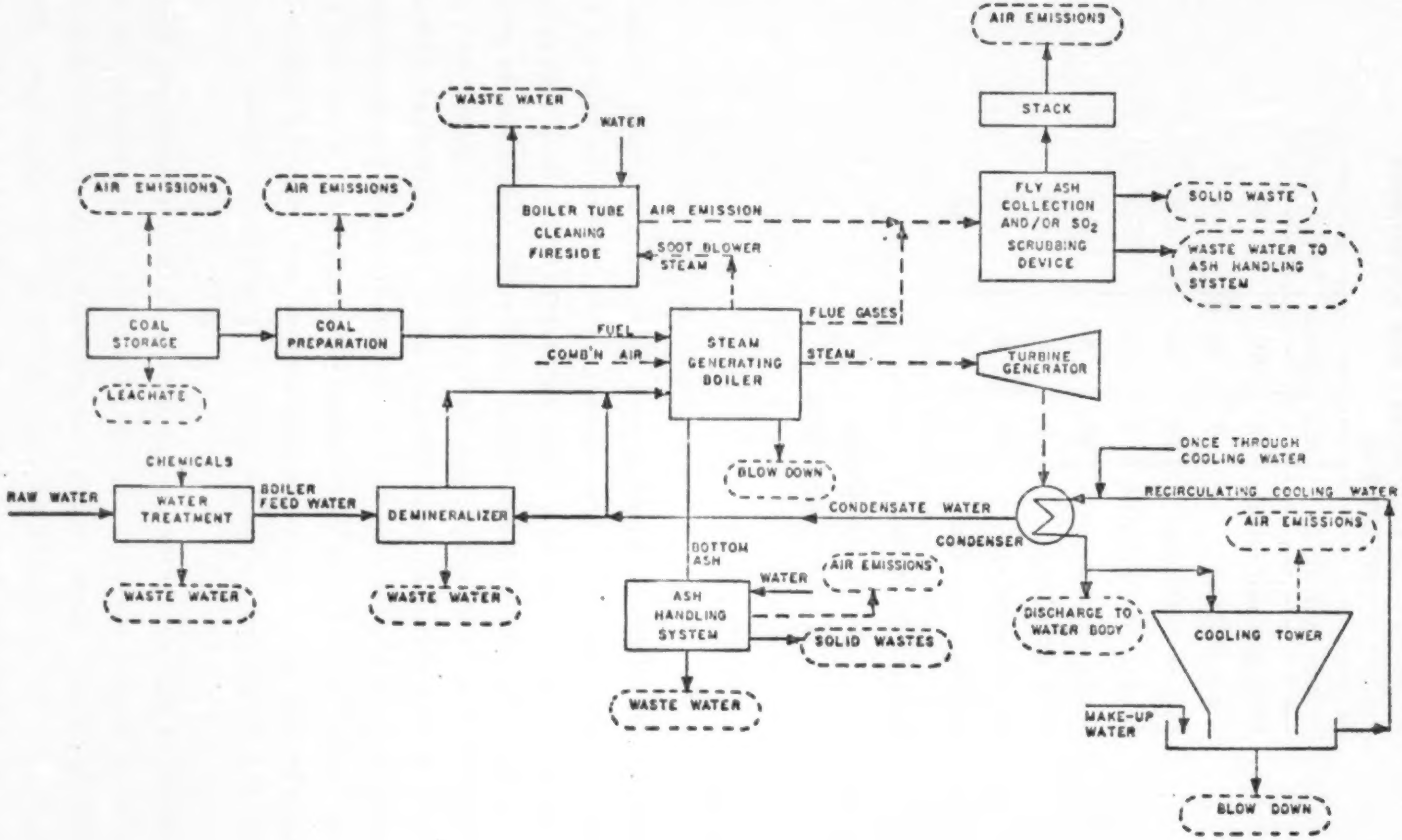
AIR EMISSIONS
STACK
WASTE WATER
WATER
AIR EMISSIONS
AIR EMISSIONS
BOILER TUBE CLEANING FIRESIDE
AIR EMISSION
SOOT BLOWER STEAM
FLY ASH COLLECTION AND/OR SO_2 SCRUBBING DEVICE
SOLID WASTE
WASTE WATER TO ASH HANDLING SYSTEM
COAL STORAGE
COAL PREPARATION
FUEL
COMB'N AIR
STEAM GENERATING BOILER
FLUE GASES
STEAM
TURBINE GENERATOR
LEACHATE
BLOW DOWN
ONCE THROUGH COOLING WATER
CHEMICALS
RAW WATER
WATER TREATMENT
BOILER FEED WATER
DEMINERALIZER
CONDENSATE WATER
RECIRCULATING COOLING WATER
CONDENSER
AIR EMISSIONS
BOTTOM ASH
WATER
AIR EMISSIONS
ASH HANDLING SYSTEM
SOLID WASTES
WASTE WATER
WASTE WATER
WASTE WATER
DISCHARGE TO WATER BODY
COOLING TOWER
MAKE-UP WATER
BLOW DOWN

Figure 3. Emission sources: coal-fired steam-electric power plants

Table 21. APPLICABILITY OF UNIT OPERATIONS TO AIR, WATER, AND SOLID WASTE POLLUTANTS

Unit operation	Air	Water	Solid waste
Flue gas emissions	X	NA	NA
Ash handling	0	X	X
Boiler blowdown	NA	X	0
Equipment cleaning	0	X	0
Water treatment	NA	X	0
Fuel handling	0	X	0
SO_2 scrubbing	NA	X	X
Cooling systems	X	X	NA

Note: X Source

0 Minor source

NA Not applicable

Air Emissions

Air emissions from electric power plants arise from a number of sources, but primarily from the combustion furnace stack, which is usually fitted with an emission control device. The influence of control device performance on the quantity of particulate and/or SO_2 emissions is predominant. Emissions and control device performance are affected by fuel, boiler type, sulfur content, load factor, etc. The principal particulate control device used by the industry is the electrostatic precipitator. Low sulfur fuels decrease the efficiency of precipitators and the use of these fuels has hastened the development of hot side and wet wall precipitators and other approaches to control of stack emissions.

Other sources of air pollution are emissions from ash handling, cooling tower drift or spray, and fuel storage, handling, and preparation equipment and operations. These sources of air emissions are considered to be relatively minor and primarily of local or in-plant importance. However, as will be discussed in subsequent sections, very little quantitative information is available in these areas, and additional investigations are recommended.

Water Effluents

The wastewater streams associated with coal-fired utility plants are schematically presented in Figure 4. The volumes presented are typical for a 1000 MW coal-fired plant but are subject to substantial plant-to-plant variations.[23,36]

Waste waters produced by a steam electric power plant result from a number of on-site operations. Some wastes are discharged continuously while other wastes are produced intermittently on a fairly regular basis, such as daily or weekly. Other wastes are also produced intermittently, but at less frequent intervals and are generally associated with the shutdown or startup of a boiler or generating unit. Additional wastes exist that depend on climatological or other factors, an example of which is coal storage pile drainage.

Waste water is discharged continuously by cooling water systems, ash handling systems, wet scrubber flue gas cleaning systems, and boiler feedwater treatment and is discharged intermittently, on a regular basis, by treatment operations such as boiler blowdown and boiler system equipment cleaning.

Once-through cooling systems use large volumes of water and potentially cause thermal pollution, stream depletion, and contamination of downstream waters with additives used to prevent fouling of condenser surfaces. Cooling towers emit moisture and heat to the atmosphere as well as spray containing corrosion inhibitors and algicides that are added to the recirculating cooling water. Cooling tower blowdown, which is discharged to control dissolved and suspended solids concentration in the cooling water, adds to the wastewater stream as shown in Figure 4. Cooling tower designs

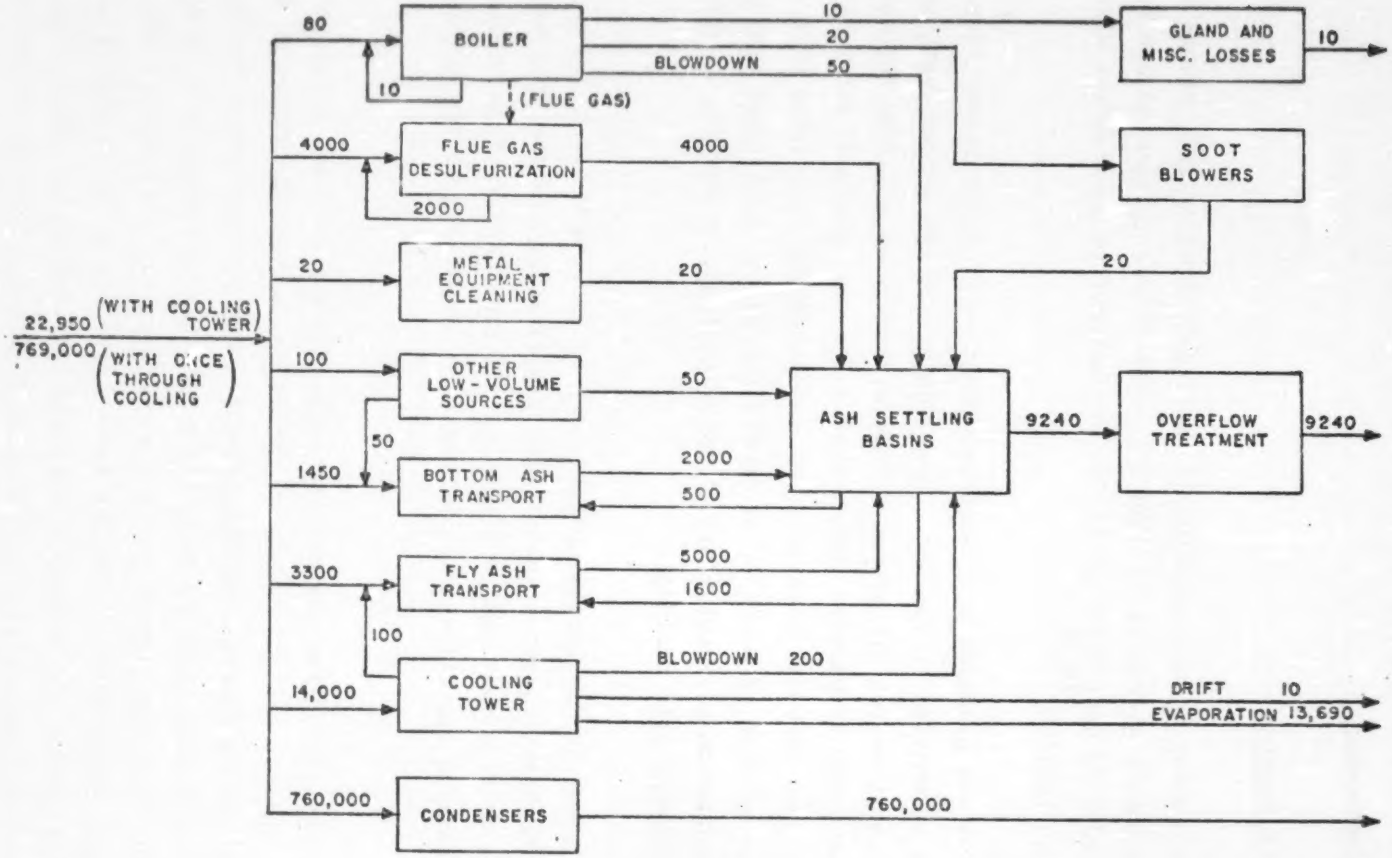
22,950 (WITH COOLING TOWER)
769,000 (WITH ONCE THROUGH COOLING)
80
BOILER
10
(FLUE GAS)
10
20
BLOWDOWN 50
GLAND AND MISC. LOSSES
10
4000
FLUE GAS DESULFURIZATION
2000
4000
SOOT BLOWERS
20
20
METAL EQUIPMENT CLEANING
20
100
OTHER LOW-VOLUME SOURCES
50
50
ASH SETTLING BASINS
9240
OVERFLOW TREATMENT
9240
1450
BOTTOM ASH TRANSPORT
2000
500
3300
FLY ASH TRANSPORT
5000
1600
100
BLOWDOWN 200
14,000
COOLING TOWER
DRIFT 10
EVAPORATION 13,690
760,000
CONDENSERS
760,000

Figure 4. Water flows for a typical 1000 MW power plant at full load (All flow values in 10^3 gpd)

are being studied at TVA plants, Battelle Memorial Institute, and EPA. The trend is toward the use of wet-dry combination and dry cooling systems in order to reduce water throughput and mitigate water pollution.

Ash handling wastes constitute a large portion of total utility effluent waste water. This waste stream can significantly contaminate receiving waters if not first discharged to a sedimentation or neutralization basin. Seepage and leaching from ash sedimentation basins are potential sources of ground water pollution but can be completely controlled by installing proper bottom materials. Ash handling requirements are minimal for oil- and gas-fired boilers. Oil-fired plants generate less than 2 percent as much ash per pound of steam as coal-fired plants. Gas-fired plants are essentially ash free, and the ash handling water requirement is extremely low.

Flue gas desulfurization processes will be an important source of waste water in the future as the use of wet scrubbers becomes more extensive.

The wastewater volumes from boiler blowdown, coal drainage, ash landfill leaching, equipment cleaning, and boiler water treatment are relatively small. They may contribute, however, to the discharge of hazardous components (PCB, oil or grease, low or high pH water, vanadium, nickel, etc.) that require further processing to reduce effluents to acceptable levels.

The major effluent water pollutants are considered in the Proposed Federal Effluent Guidelines and Standards for Steam-Electric Power Plants (see Table 22). In addition, permit applications required under the NPDES permit program often specify maximum effluent concentrations of hazardous pollutants not considered by the proposed standards and require reductions corresponding to state regulations. Each source is considered separately, and the extent of reduction depends upon the hazardous effects on the receiving water and the waste treatment method used.

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Table 22. WASTEWATER EFFLUENT GUIDELINES AND STANDARDS - STEAM ELECTRIC GENERATING POINT SOURCE CATEGORY[a]

Concentration

All values in mg/ℓ

Prominent Waste Stream Affected	Effluent Characteristics	BPT,[b] BAT,[c] and NS[d]
Feedwater treatment	pH PCB's	6-9 0

Prominent Waste Stream Affected	Effluent Characteristics	Maximum daily discharge			Average Daily Discharge for 30 Consecutive Days		
		BPT	BAT	New Source	BPT	BAT	New Source
Equipment cleaning blowdown	TSS	100	100	100	30	30	30
	Oil and Grease	20	20	20	15	15	15
	Copper	1	1	1	1	1	1
	Iron	1	1	1	1	1	1

Prominent Waste Stream Affected	Effluent Characteristics	BPT		BAT		New source						
		Low Volume and Ash Transport		Low Volume and Fly Ash Sluicing		Bottom Ash Transport		Low Volume		Bottom Ash Transport		Fly Ash Transport
		Maximum Daily	Average Daily for 30 days	Maximum Daily	Average Daily for 30 Days	Maximum Daily	Average Daily for 30 Days	Maximum Daily	Average Daily for 30 Days	Maximum Daily	Average Daily for 30 days	
Fuel Handling Ash Handling	TSS	100	30	100	30	8	2.4	100	30	5	1.5	0
	Oil and Grease	20	15	20	15	1.6	1.2	20	15	1	0.75	0

Prominent Waste Stream Affected	Effluent Characteristics	Maximum Concentration			Average Concentration			Maximum Daily Discharge			Average Daily Discharge for 30 Consecutive Days		
		BPT	BAT	NS	BPT	BAT	NS	BPT	BAT	NS	BPT	BAT	NS
Cooling	Free Available Cl	0.5	0.5	0.5	0.2	0.2	0.2			No detectable amount			No detectable amount
	Zn							-	1.0		-	1.0	
	Cr							-	0.2		-	0.2	
	P							-	5.0		-	5.0	

[a] Steam Electric Power Generating Point Source Category - **Effluent Guidelines and Standards.** Federal Register, Vol. 39, No. 196. October 8, 1974.

[b] **Best practicable control technology currently available.**

[c] **Best available control technology economically achievable.**

[d] **New source.**

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Table 23 is a summary of the potential water pollution effects related to steam-generation power plants. Wastewater volumes are presented for all fossil-fueled plants and separated for coal-fired plants because this sector produces the largest portion of waste water. Continuous flow quantities are shown in order to provide a basis for comparing individual waste sources.

A variety of trace elements dissolved in water are emitted from stationary combustion facilities and related processes. Table 24 is a listing of trace element concentrations measured in various effluent streams and is compiled from a variety of studies.[36,127,183-185] Table 25 is extracted from a recent EPA document[36] and shows net discharge of pollutants emitted from ash settling pond overflow. The positive and negative values are referenced to the make-up water used for sluicing the ash to the settling pond. It is difficult to determine absolute values for overflow concentrations due to variation in ambient make-up water quality and degree of reuse of contaminated sluicing water.

Solid Waste

Solid waste pollutants are generated by ash disposal. In addition, SO_2 scrubbing systems will present a major solid waste disposal problem if, in the future, flue gas scrubbing becomes widely adopted. Approximately 80 percent of the fly ash and bottom ash collected becomes landfill that may pollute water and soil by leaching and runoff and by erosion of landfill surfaces. At present only a small percentage of fly ash (~20 percent) finds its way into applications other than landfill. Studies on the expanded utilization of ash, currently produced at 50,000,000 tons annually, need to be encouraged.

Thermal and Noise Pollution

The major source of thermal water pollution is the boiler water cooling system, particularly in the case of once-through systems. Power plant

Table 23. IMPORTANT ASPECTS OF WATER WASTES

Waste generating process	Duration of flow	Wastewater flow quantities				Important pollutional characteristics	Associated[a,b] hazardous ambient effects	Overall assessment of hazard
		All boilers		Coal-fired boilers				
		10^9 gal/yr	Total solids, 10^3 ton	10^9 gal/yr	Total solids, 10^3 ton			
Ash handling	Continuous	280[c]	2400	280[c]	2400	TS - 300-3500 mg/ℓ, trace elements, Organics	Possible D.O. reduction; production of color, turbidity, and odor; interference with water reuse.	The quantity of flow and solids concentration is high. With conventional ponding and lagooning of ash wastes, the solids concentration is significantly reduced. The average effluent TSS is 100 mg/ℓ.[c]
Cooling						ΔT - +15°F, Free Cl residual - 0.1-1.0 mg/ℓ	D.O. reduction resulting in fish kills and lowered capacity for natural water processes.	Significant hazard with both systems. The large flow quantity is the major cause of the adverse impact.
Once-through								
Fresh	Continuous	33,000[d]		23,000[d]				
Saline	Continuous	16,000		1,600				
Recirculative	Continuous	5,300	275	2,700	140			
Fuel handling	Intermittent	7.9[c,e]	670	7.9[c,e]	670	TS - 1500-45,000 mg/ℓ, Acidity - 10-28,000 mg/ℓ	Hazards to fish and impairment of water for recreational and consumptive use; possible D.O. reduction.	Minor ambient hazards for properly collected and treated waste flows. Shock effects may be significant for underdesigned systems and/or prolonged rainfall.
Boiler feedwater treatment	Continuous	9.0[c]	1100	5.2[c]	640	TS - 30,000 mg/ℓ, Hardness - 3,000 mg/ℓ	Possible D.O. reduction; production of color, turbidity, and odor; interference with water reuse.	The waste generated is no greater than that present in the influent water, but it is considerably more concentrated. Lagooning and sedimentation combined with a low flow volume give rise to an overall waste which is nonhazardous.
Boiler blowdown	Intermittent	6.6[c]	5.6	3.8[c]	3.2	Phosphates - 5-50 mg/ℓ, Alkalinity - 10-100 mg/ℓ	Eutrophication and solids sedimentation.	The phosphate concentration is well above values reported to cause nuisance algal blooms. The effect may be particularly severe in impounded waters. The low flow quantity relieves the situation.
Equipment cleaning	Infrequent - once/2 years	2.2[c]	130	1.3[c]	77	TS - 14,000 mg/ℓ, Hardness - 4,000 mg/ℓ	Possible D.O. reduction; production of color, turbidity, and odor; interference with water reuse.	The extreme infrequency of discharge transforms this into a problem of controlling intermittent, but substantial, shock effects in the ambient water.

[a] Fair, G. M., J. C. Geyer, D. A. Okun. Water Purification and Waste Water Treatment and Disposal: Volume II of Water and Waste Water Engineering. John Wiley and Sons. 1968.

[b] McGauhey, P. H. Engineering Management of Water Quality. McGraw-Hill Book Co. 1968.

[c] Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. U.S. EPA Report No. EPA-440/1-74-029a. October 1974.

[d] Steam Electric Plant Air and Water Quality Data. Summary Report FPC-S-239.

[e] Edison Electric Institute. A Summary of the Processes Involved and the Chemical Discharges Associated with the Electric Utility Industry.

Table 24. TRACE ELEMENT CONCENTRATIONS IN WASTE STREAMS (mg/ℓ)

	Al	Sb	As	Ba	Be	B	Cd	Ca	Cℓ	Cr	Co	Cu
Ash pond liquor[a]		0.015	0.01	0.07	0.002	0.5	0.01					
Ash sluice ponds[b]						<100-1600						
Ash sluicing water[c]	9.2	0.004	<0.0001	<0.60	<0.002	0.5	<0.002	114	14.9	<0.05	<0.003	0.022
Bottom ash sluice water[d]	1.69	0.034	0.008	<0.5	0.002	0.25	0.001	45	15.7	<0.05	0.004	0.011
Bottom ash sluice water[e]	2.31	0.041	0.004	0.5	0.001	2.46	0.004	785	27.7	<0.05	0.005	0.024
Economizer ash sluice water[d]	0.57	0.021	0.001	<0.5	0.003	2.41	0.001	46	17.2		0.003	0.008
Scrubber liquid[f]	0.03-0.3	0.09-2.3	<0.004-0.3		<0.002-0.14	8-46	0.004-0.11	520-3000		0.01-0.5	0.10-0.7	<0.002-0.2
Scrubber liquid[e]	4.8	0.04	0.001	0.48	0.002	2.9	0.007	910	27.9	0.14	0.011	0.048
Coal pile drainage[g]	825-1200								20-480	0-16	0.025	1.6-3.9
Cooling tower blowdown[e]	2.27	0.023	0.003	0.50	0.004	0.27	0.001	140	25	<0.06		0.25

	F	Fe	Pb	Mg	Mn	Hg	Mb	N in NH_3	N in NO_x	Ni	P	K	Se
Ash pond liquor[a]			0.01		0.075	<0.001							0.035
Ash sluice ponds[b]								0.1-2.0	0.1	0.015	0.1-0.6		
Ash sluicing water[c]	0.70	0.01	0.006	15.7	0.016	<0.0004	0.015			<0.02			0.004
Bottom ash sluice water[d]	0.25	2.25	0.024	25.8	0.055	<0.0004	0.016			0.001			0.001
Bottom ash sluice water[e]	16.2	0.31	0.007	67.7	0.77	0.0005	0.055			0.015			0.031
Economizer ash sluice water[d]	0.023	1.38	0.025	24.1	0,096	0.0005	0.012			0.007			0.001
Scrubber liquid[f]		0.02-8.1	0.01-0.4	3-2750	0.09-2.5	0.0004-0.07	0.91-6.3			0.05-1.5		5.9-32	<0.001-2.2
Scrubber liquid[e]	20.0	0.71	0.023	61.7	0.88	0.0007	0.015			0.015			0.12
Coal pile drainage[g]		0.4-2.0		90-180							0.2-1.2		
Cooling tower blowdown[e]	0.91	1.14	0.016	36.4	0.10	0.0005	0.05			0.005			0.004

Table 24 (continued). TRACE ELEMENT CONCENTRATIONS IN WASTE STREAMS (mg/ℓ)

	Si	Ag	Na	S	Sulfite $SO_3^=$	Sulfate $SO_4^=$	Sn	Ti	U	V	Zn
Ash pond liquor[a]											
Ash sluice ponds[b]											
Ash sluicing water[c]		<0.0002		108				<0.1	0.004	0.072	0.008
Bottom ash sluice water[d]		<0.0002		73				<0.1	0.003	<0.005	0.013
Bottom ash sluice water[e]		0.0004		765				0.1	0.005	0.192	0.075
Economizer ash sluice water[d]		<0.0002		77				<0.1	0.005	<0.005	0.028
Scrubber liquid[f]	0.2-3.3	0.005-0.6	14-2400		1-3500	720-10,000	3.1-3.5			0.001-0.67	0.01-0.35
Scrubber liquid[e]		0.0005		860				<0.1	0.009	0.23	0.088
Coal pile drainage[g]			160-1260			130-20,000					
Cooling tower blowdown[e]		0.0004		2700				<0.09	0.015	0.141	0.409

[a] Rossoff, J., et al. Study of Disposal and Utilization of Byproducts from Throwaway Desulfurization Processes. Flue Gas Desulfurization Symposium. The Aerospace Corporation. U.S. EPA Report No. 650/2-73-038. December 1973.

[b] Rohrman, F.A. Analyzing the Effect of Fly Ash on Water Pollution, Power, August 1971.

[c] Coal-Fired Power Plant Trace Element Study, Volume III, Station II. Radian Corporation, September 1975.

[d] Coal-Fired Power Plant Trace Element Study, Volume IV, Station III. Radian Corporation, September 1975.

[e] Coal-Fired Power Plant Trace Element Study, Volume II, Station I. Radian Corporation, September 1975.

[f] Bornstein, L.J., et al. Reuse of Power Plant Desulfurization Waste Water. Aerospace Report No. ATR-75(7448)-1. The Aerospace Corporation. Prepared for Pacific Northwest Water Laboratory, National Environmental Research Center. Office of Research and Development, U.S. Environmental Protection Agency, Corvallis, Oregon. June 1975.

[g] Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam-Electric Power Generating Point Source Category. U.S. EPA Report No. 440/1-74-029a. October 1974.

Table 25. ASH POND OVERFLOW

Plant code	Plant capacity		Fuel	Flow	Al	Cr	Cu	Fe	Mn	Mg	Hg	Na	Ni	Zn	P
	MW	MWhr/day	c - coal o - oil	1000 gpd											
3412	1114.5	13,205	c/o	5,170	0.075	-0.113	-0.001	-0.479	-	156	-	0	-0.054	-0.014	-
3416	740	10,525	c	3,460	-	0	0	0.045	-	-	-	-4	-	0.162	-
3404	300	5,420	c/o	675	-	-	-	-	-	-	-	-	-	0.00013	0
3402	308	4,965	c/o	720	-	0.01	-0.006	-4.6	-	-11	-	-	-	-	0
3401	31	865	c	2,412	-	-	-	-	-	-	-	52	-	0.17	-
3405	116.2	1,629	c/o	4.8	-	0.139	-	-	-	-	-	-1609	-	0.117	-0.5
1703	766	6,288	c	6,000	-	0.00001	-	-	-	-	-	-	-	0	-0.33
1720	1178	16,155	c	13,000	0.011	-0.014	-	0.6	-	18	-	982	-	-0.073	-0.7
1710	1162	3,164	c/o	720	-	-	-	-	-	-	-	-	-	-	-
1722	1232	15,563	c	26,000	0.15	-	-	0.28	0.02	25	0.0002	26	0.01	0.03	-0.09
1709	690	0,706	o	1,000	0.1	-	0.02	0.001	0.0002	-	-	-	-	0.011	-1.19
1711				8,600	0	0	-	0	-	-3	-	-3	-	-	-0.7
1711				700	-0.145	-0.03	-	-0.252	-	10	-	173	-	-	-
1711[a]	1179	21,872	c	9,300					-					-	
3936				1,000	-	0.0005	-	0.034	-	15		30	-	0.009	0.1
3936				6,000	-	0.007	-	0.040	-	14	-	32	-	0.009	0.2
3936[a]	1086	18,908	c	7,000	-		-		-						
3927	1469	21,705	c	1,400	0.153	0.011	0.005	0.099	0.076	21	-	73	0.011	0.003	0.14
2616	933	14,276	c	4,200	1.67	-	-	1.770	-	0.1	-	14	-	-	0
1804	732	12,050	c	4,000	-	-	-	-	-	-	-	-	-	-0.01	0.26
1729	186	2,978	c	480	-	-	-0.037	-0.593	-	-	-0.002	-	-	-	0.08
1718	1042	13,855	c/o	14,000	1.[illegible]50	0.001	-	-0.387	-	-2	-	3	-	0.03	-0.05
3930				4,000	0.021	-	-	-	-	-	-	92	0.015	0.003	-
3930				1,000	0.021	-	-	-	-	-	-	88	0.008	0.013	-
3930[a]	500	3,816	c	5,000											
1825				9,800	-	0.080	-	0.02	-	0	-	27	-	0.07	-
1825				3,200	-	0.004	-	0.09	-	12	-	23	-	-0.007	-
1825				1,600	-	0.007	-	0.032	-	11	-	18	-	-0.006	-
1825				30	-	0.005	-	0.098	-	12	-	37	-	0.001	-
1825[a]	1304	24,813	c	14,630				0.141							
3920	544	7,695	c	7,200	-	-	-	-	-	-	-	-	-	-	-0.09
1816	600	10,149	c	1,000	6	-	-	-	-	-	-	-	-	-	0.41
2608	510	7,550	c	1,500	-	-	-	-	-	-	-	23	-	-	-0.06
0111	1300	18,169	c	7,338	-	-	-	0.44	-0.02	-3.8	-	-	-	-	-
4704	823	9,874	c	4,076	-	-	-	2.894	0.102	-1.9	-	-	-	-	-
2119				10,748	-	-	-	-	-	-	-	-	-	-	-
2119				21,725	-	-	-	-	-	-	-	-	-	-	-
2119[a]	2558	31,458	c	32,473	-	-								-	
0107	568	5,741	c	720	5.30	0	0.06	0.15	-	-	0	-	-	0.05	-
3514	2152	11,315	c	2,870	-	-	-	-	-	10		-	-	-	-
1716				500	-0.22	-	-	-	-	6	-	-45	-	0.12	-0.23
1716				150	0.1	-	-	-	-	18	-	-136	-	-0.02	-0.23
1716[a]	676	11,092	c	650	-0.12										

[a] Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category. U.S. EPA. Report No. 440/1-74-029a. October, 1974.

noise is attributable to many sources but arises mostly from cooling tower draft fans and from the sootblower, pressure reducing, and continuous blowdown valves. Methods of reducing noise levels to acceptable values are available.

FLUE GAS EMISSIONS

The electric utility industry is a major contributor to the burden of air pollutant emissions to the environment. Based on this report, the industry's contribution to the "man-made" criteria pollutant discharges to air are as shown in Table 26. The majority of air pollutant emissions from the electric utility industry are from the combustion stack. Total nationwide emission estimates of particulates (including < 3 micron diameter particulates), sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, polycyclic organic matter, and trace elements are presented in the following sections for both external and internal combustion sources.

Table 26. THE ELECTRIC UTILITY INDUSTRY'S CONTRIBUTION TO AIR POLLUTANT EMISSIONS

Pollutant	Percent of U.S. total man-made emissions	Percent of stationary combustion source emissions
Particulate	13	64
SO_x	52	73
NO_x	29	65
HC	0.3	34
CO	0.2	34

External Combustion

The generation of electricity by utilities via external combustion accounts for 13 percent of total particulates, 52 percent of sulfur oxides, 26 percent of nitrogen oxides, 0.2 percent of hydrocarbons, and 0.2 percent of carbon monoxide emissions from all man-made sources. It accounts for 64 percent of total particulates, 72 percent of sulfur oxides, 59 percent of nitrogen oxides, 24 percent of hydrocarbons, and 25 percent of carbon monoxide emissions from the conventional stationary combustion systems considered in this study.

Detailed emission estimates for the United States are presented in Table 27. The estimates of criteria pollutants are based on the EPA-NEDS emission factors[9] listed in Table 28 and the methods described in the notes following Table 27. Trace element and polycyclic organic matter emissions were estimated by GCA as presented in Table 27 and as described in the notes following Table 27.

To obtain state emission estimates for purposes of assigning priorities to the various combustion systems it will be necessary to prorate the nationwide values by multiplying by the ratio of the fuel consumption in a state (ton/year) to the fuel consumption nationwide (ton/year). Fuel consumption estimates by state are provided in Appendix B. Additional data on trace element content are provided in Appendix C. As a further aid to assigning priorities, frequency factors have been assigned to all combustion systems. These frequency factors are required inputs to the priority model now being developed by Monsanto Research Corporation.

In the subsections that follow, each pollutant listed above is discussed in detail. The discussions include general reviews and analyses of pertinent literature and specific reviews of the data sources used to estimate nationwide emissions.

Table 27. STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[i] tons/yr		
		Total	< 3μ[h]	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
1.0.00.0.0	Electric Generation	4,500	1,600	16,000	7,100	120	360	11,000	11	0.8
1.1.00.0.0	External Combustion	4,500	1,600	16,000	6,500	85	270	11,000	11	0.8
1.1.10.0.0	Coal	4,400	1,500	14,000	4,700	64	210	10,000	10	0.75
1.1.11.0.0	Bituminous[b]	4,300	1,500	14,000	4,600	57	200	9,700	10	0.73
1.1.11.1.0	Pulverized Dry	3,500	1,200	10,000	2,400	41	140	7,000	7.3	0.52
1.1.11.2.0	Pulverized Wet	500	180	1,900	760	7.6	26	1,300	1.3	0.1
1.1.11.3.0	Cyclone	250	100	1,900	1,400	7.6	26	1,300	1.3	0.1
1.1.11.4.0	All Stokers	76	12	99	20	1.2	2.6	58	0.06	0.006
1.1.12.0.0	Anthracite[c]	21	6.5	41	12	0.098	1.2	50	0.05	0.004
1.1.12.1.0	Pulverized Dry	17	6.0	15	4.6	0.008	0.26	15	0.015	0.001
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	3.8	0.53	26	7.1	0.09	0.95	35	0.035	0.003
1.1.13.0.0	Lignite[d]	82	30	120	72	6.2	6.9	250	0.25	0.02
1.1.13.1.0	Pulverized Dry	50	18	74	42	3.7	3.7	150	15	0.01
1.1.13.2.0	Pulverized Wet	13	4.6	19	10	1.0	1.0	40	4.0	0.003
1.1.13.3.0	Cyclone	11	5.7	19	16	0.93	0.93	38	3.8	0.003
1.1.13.4.0	All Stokers	8.4	1.2	12	3.8	0.63	1.3	25	2.5	0.002
1.1.20.0.0	Petroleum	78	71	1,500	810	19	30	300	0.3	0.02
1.1.21.0.0	Residual Oil[e]	74	67	1,500	770	18	28	300	0.3	0.02
1.1.21.0.1	Tangential Firing	29	26	570	180	7.2	11	130	0.13	0.008
1.1.21.0.2	All Other	45	41	890	590	11	17	170	0.17	0.012
1.1.22.0.0	Distillate Oil[f]	3.9	3.6	16	41	0.99	1.5	14	0.014	0.001
1.1.22.0.1	Tangential Firing	1.5	1.4	6.1	9.6	0.38	0.58	6	0.006	0.0004
1.1.22.0.2	All Other	2.4	2.2	9.6	32	0.61	0.90	8	0.008	0.0006
1.1.30.0.0	Gas[g]	16	14	0.95	960	1.6	27	360	0.35	0.03
1.1.30.0.1	Tangential Firing	3.9	3.5	0.23	120	0.39	6.6	90	0.09	0.008
1.1.30.0.2	All Other	12	11	0.72	840	1.2	20.5	270	0.27	0.022

Table 27 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION[a]

		Trace elements,[j] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
1.0.00.0.0	Electric Generation	51	3,000	2,700	230	98	5,000	5,600	200	590,000	1,500
1.1.00.0.0	External Combustion	51	3,000	2,700	230	98	5,000	5,600	200	590,000	1,500
1.1.10.0.0	Coal[k]	48	3,000	2,700	220	98	5,000	5,600	54	590,000	1,400
1.1.11.0.0	Bituminous[l]	48	3,000	2,000	220	93	4,900	5,600	54	560,000	1,300
1.1.11.1.0	Pulverized Dry	35	2,200	1,400	160	67	3,500	4,000	39	400,000	930
1.1.11.2.0	Pulverized Wet	6.3	410	270	30	13	660	760	7.3	76,000	180
1.1.11.3.0	Cyclone	6.3	410	270	30	13	660	760	7.3	76,000	180
1.1.11.4.0	All Stokers	0.33	21	14	1.5	0.64	34	39	0.38	3,900	9.3
1.1.12.0.0	Anthracite[m]	0.04	3.7	13	1.1	0.04	0.37	1.5	0.05	2,200	44
1.1.12.1.0	Pulverized Dry	0.01	1.3	4.5	0.38	0.01	0.13	0.51	0.02	770	15
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	0.03	2.4	8.3	0.71	0.03	0.24	0.95	0.03	1,400	29
1.1.13.0.0	Lignite[n]			650	0.71	5.0	130	0.57		25,000	13
1.1.13.1.0	Pulverized Dry			390	0.43	3.0	77	0.36		15,000	7.7
1.1.13.2.0	Pulverized Wet			97	0.11	0.75	19	0.08		3,800	1.9
1.1.13.3.0	Cyclone			97	0.11	0.75	19	0.08		3,800	1.9
1.1.13.4.0	All Stokers			65	0.07	0.5	13	0.06		2,500	1.3
1.1.20.0.0	Petroleum[o]	2.9	22	48	6.8		8.0	12	150	1,200	130
1.1.21.0.0	Residual Oil[p]	2.9	22	48	6.8		8.0	12	150	1,200	130
1.1.21.0.1	Tangential Firing	1.1	8	19	2.6		3.0	4.8	57	450	50
1.1.21.0.2	All Other	1.8	13	29	4.2		5.0	7.5	89	710	80
1.1.22.0.0	Distillate Oil[q]	ND	0.16	ND				0.04	ND		ND
1.1.22.0.1	Tangential Firing	ND	0.04	ND				0.01	ND		ND
1.1.22.0.2	All other	ND	0.12	ND				0.03	ND		ND
1.1.30.0.0	Gas[r]										
1.1.30.0.1	Tangential Firing										
1.1.30.0.2	All other										

Table 27 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION[a]

		Trace elements,[j] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
1.0.00.0.0	Electric Generation	320	2,000	31,000	131,000	1,200	4,500	48	510	4,900	740
1.1.00.0.0	External Combustion	320	2,000	31,000	131,000	1,200	4,500	48	510	4,900	740
1.1.10.0.0	Coal[k]	160	1,300	31,000	131,000	1,200	4,500	47	350	1,300	730
1.1.11.0.0	Bituminous[l]	140	1,200	31,000	130,000	1,200	4,300	47	340	1,300	730
1.1.11.1.0	Pulverized Dry	100	860	22,000	93,000	860	3,100	34	240	930	520
1.1.11.2.0	Pulverized Wet	19	160	4,100	18,000	160	590	6.3	46	180	99
1.1.11.3.0	Cyclone	19	160	4,100	18,000	160	590	6.3	46	180	99
1.1.11.4.0	All Stokers	1.0	8.2	210	930	8.3	29	0.33	2.4	9.3	5.1
1.1.12.0.0	Anthracite[m]	13	27	160	1,000	4.6	5.1	0.40	3.7	18	0.20
1.1.12.1.0	Pulverized Dry	4.6	9.6	56	350	1.6	1.8	0.14	1.3	6.4	0.07
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	8.5	18	100	650	3.0	3.3	0.26	2.4	12	0.13
1.1.13.0.0	Lignite[n]	5.5	26			28	170		4.9	8.7	
1.1.13.1.0	Pulverized Dry	3.3	15			17	100		2.9	5.2	
1.1.13.2.0	Pulverized Wet	0.82	3.9			4.1	26		0.73	1.3	
1.1.13.3.0	Cyclone	0.82	3.9			4.1	26		0.73	1.3	
1.1.13.4.0	All Stokers	0.55	2.6			2.8	17		0.49	0.87	
1.1.20.0.0	Petroleum[o]	160	720	0.29	520	2.9	12	1.4	160	3,600	9.9
1.1.21.0.0	Residual Oil[p]	160	720	0.29	520	2.9	12	1.4	160	3,600	9.9
1.1.21.0.1	Tangential Firing	63	280	0.11	200	1.1	4.4	0.6	64	1,400	3.9
1.1.21.0.2	All Other	98	440	0.18	320	1.8	7.2	0.8	100	2,200	6.0
1.1.22.0.0	Distillate Oil[q]		0.08				0.020	ND		ND	ND
1.1.22.0.1	Tangential Firing		0.032				0,008	ND		ND	ND
1.1.22.0.2	All Other		0.048				0.012	ND		ND	ND
1.1.30.0.0	Gas[r]										
1.1.30.0.1	Tangential Firing										
1.1.30.0.2	All Other										

Table 27 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION[a]

		Trace elements,[j] tons/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
1.0.00.0.0	Electric Generation	28	9.3	100	55,000	1,500	6,700	2,000	1,800
1.1.00.0.0	External Combustion	28	9.3	100	55,000	1,500	6,700	2,000	1,800
1.1.10.0.0	Coal[k]	28	9.3	98	55,000	1,400	2,600	2,000	1,800
1.1.11.0.0	Bituminous[l]	28	9.3	88	55,000	1,400	2,600	2,000	1,700
1.1.11.1.0	Pulverized Dry	20	6.7	63	39,000	1,000	1,900	1,400	1,200
1.1.11.2.0	Pulverized Wet	3.8	1.3	12	7,400	190	350	270	230
1.1.11.3.0	Cyclone	3.8	1.3	12	7,400	190	350	270	230
1.1.11.4.0	All Stokers	0.20	0.064	0.64	380	9.9	18	14	12
1.1.12.0.0	Anthracite[m]	0.04	0.04	0.37	220	0.11	5.7	12	6.8
1.1.12.1.0	Pulverized Dry	0.01	0.01	0.13	77	0.04	2.0	4.2	2.4
1.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	0	0	0
1.1.12.4.0	All Stokers	0.03	0.03	0.24	140	0.07	3.7	7.8	4.4
1.1.13.0.0	Lignite[n]			10			32	5.8	100
1.1.13.1.0	Pulverized Dry			5.5			19	3.5	60
1.1.13.2.0	Pulverized Wet			1.4			4.8	0.86	15
1.1.13.3.0	Cyclone			1.4			4.8	0.86	15
1.1.13.4.0	All Stokers			0.92			3.3	0.58	10
1.1.20.0.0	Petroleum[o]			6.4	390	100	4,100	5.6	
1.1.21.0.0	Residual Oil[p]			0.08	390	100	4,100	5.6	
1.1.21.0.1	Tangential Firing			0.032	150	39	1,600	2.2	
1.1.21.0.2	All Other			0.048	240	60	2,500	3.4	
1.1.22.0.0	Distillate Oil[q]			6.4			ND	ND	
1.1.22.0.1	Tangential Firing			2.5			ND	ND	
1.1.22.0.2	All Other			3.9			ND	ND	
1.1.30.0.0	Gas[r]								
1.1.30.0.1	Tangential Firing								
1.1.30.0.2	All Other								

Table 27 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION[a]

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[a] Values in the table represent total estimated emissions to the atmosphere from conventional stationary combustion sources in the United States. An entry of "ND" signifies that a trace element has not been detected when measured and an entry left blank signifies that no information is available. The emission factors used for this table are given in Table 28.

[b] The consumption data for bituminous coal were obtained from reference 6. The breakdown of the boiler population used was: pulverized dry bottom 72.3 percent, pulverized wet bottom 13.5 percent, cyclone boilers 13.5 percent, and spreader stokers 0.7 percent. The particulate control efficiencies and the percentage of boilers using controls were multiplied and subtracted from unity to obtain the fractions of the total particulates that escape. For pulverized units this escape number is 0.11, for cyclone units 0.35, and for stokers 0.30.

The sulfur content of bituminous coal was 2 percent and the ash content was 13.85 percent, according to reference 23.

[c] Anthracite coal consumption data were taken from references 6 and 19. The breakdown of the boiler population used was: pulverized dry 35 percent and stoker 65 percent. The particulate control efficiencies and the percentage of boilers using controls were multiplied and subtracted from unity to obtain the fractions of particulates that escape. For anthracite coal this escape number was estimated to be 0.40 based on age and control efficiency data, using reference 6. The sulfur content of anthracite coal was 1.0 percent and the ash content was 10 percent, using reference 23.

[d] The consumption data for lignite were obtained from references 18 and 20. The breakdown of the boiler population was: pulverized dry 60 percent, pulverized wet 15 percent, cyclone boiler 15 percent, and stoker 10 percent. The particulate control efficiency and the percentage of boilers using control equipment were multiplied and subtracted from unity to obtain the fractions of particulates that escape. For lignite this escape number is 0.20, based upon analysis of data from reference 23. The sulfur content of lignite was 0.66 percent and the ash content 9.6 percent, using reference 23.

[e] The consumption figures for residual oil were taken from reference 6. The breakdown of the boiler population was: 38.9 percent tangential firing and 61.1 percent for all others. Sulfur content was 1 percent using reference 6. The particulate control escape number was 0.90.

[f] The consumption data for distillate oil were taken from reference 6. The breakdown of the boiler population was 38.9 percent tangential firing and 61.1 percent for all others. The particulate control escape number was 0.90.

Table 27 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION[a]

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[g] Natural gas consumption data were obtained from reference 6. The boiler population was: 24.3 percent for tangential and 75.7 percent for all other boilers. The particulate control escape number is 1.0 as particulate control devices are not used on gas-fired boilers.

[h] Emissions of <3 micron particles for coal were calculated by multiplying total particulate emissions by 0.35 for pulverized dry units, 0.35 for pulverized wet units, 0.52 for cyclones, and 0.14 for stokers as given in Table 29. For oil and gas, emissions of <3 micron particles were assumed to be 90 percent of the total particulate emissions as given in Table 30.

[i] Emissions of BaP were calculated from 1974 consumption data from reference 6 and emission factors from reference 37. The emissions of particulate polycyclic organic matter (PPOM) were based on the ratio of PPOM to BaP found in organic emissions from utility boilers. The emissions of benzene soluble organics (BSO) were based on the ratio of BSO to PPOM found in organic emissions of utility boilers.

[j] The amount of each trace element i emitted to the atmosphere was calculated as follows:

(1) The amount of i in the fuel, A_i, was

$$A_i = C_i \times F_i$$

where C_i = concentration of i in the fuel, ppm

F_i = yearly consumption of fuel, tons/year

If A_i was calculated on a regional basis, results were summed to the national level.

(2) The amount emitted to the atmosphere, E_i, was

$$E_i = A_i \times f_i$$

where f_i = estimated fraction of i emitted to the atmosphere. See Table 41 for values of f_i. For oil f_i was assumed to equal 1.

[k] Data for coal were available for each of the coal-producing regions defined by the U.S. Geological Survey. Sources of trace element concentration data were publications by Magee,[38] Zubovic,[39] Kessler,[40] Ruch,[41] and von Lehmden.[42,43] The Bureau of Mines[44] was a source of coal distribution data.

Table 27 (continued). STACK EMISSIONS FROM THE GENERATION OF ELECTRICITY BY EXTERNAL COMBUSTION[a]

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[l] For each coal-producing region, concentrations of As, Ba, Be, B, Cr, Co, Cu, F, Pb, Mn, Hg, Mo, Ni, Sn, U, V, and Zn in bituminous coal were calculated using reference 38 as a primary source and reference 39 as a supplementary source. For Cl, Br, and Ti, data from Illinois in reference 41 were considered as typical of all coal-producing regions. For Sb, Bi, Cd, Fe, Te, Tl, and Zr concentrations were calculated by using reference 40. For Se the single concentration cited by reference 43 was used.

Bituminous coal consumption in the geographical regions used by the U.S. Department of Commerce was related to coal shipments from the coal-producing regions using reference 44. For further details, see Appendix B.

[m] For anthracite coal, typical trace element concentrations were taken from reference 40. A total anthracite consumption in 1974 of 1.46 x 10^6 tons was obtained from references 6 and 19.

[n] For lignite, reference 38 supplied the data for North Dakota lignite and reference 39 supplied the data for Texas lignite. Reference 38 contained data for the elements As, Ba, Be, Bi, B, Br, Co, Cu, Cr, Mn, Mo, Ni, Sn, V, Zn, and Zr. Reference 39 contained data for the elements Be, Br, Co, Cu, Mo, Ni, Sn, V, and Zr. A concentration of Cl in lignite was obtained from reference 45. Lignite consumption in 1974 consisted of 6.8 x 10^6 tons from North Dakota and 5.7 x 10^6 tons from Texas, according to reference 15.

[o] Data on petroleum were taken from reference 46. The oil producing regions were listed as the U.S., Canada, South America, Mideast, Africa, and Asia.

[p] For residual oil, trace element concentration data were available for As, Sb, Ba, Br, Cr, Mn, Ni, V, and Zn from reference 46. For the trace elements Be, B, Cd, Co, F, Fe, Pb, Hg, Mo, Se, Sn, Ti, and U reference 42 was used as the primary source and references 43, 47, 48 and 49 as supplementary sources. Data on shipments from the producing regions for consumption in the United States were obtained from reference 50. See Appendix B for further details.

[q] For distillate oil, reference 46 reported concentrations for As, Br, Cu, Mn, and Sn and reported that Sb, Ba, Cd, Cr, Hg, Ni, Se, V, and Zn were not detectable.

[r] Hydrocarbon gases were assumed to be free of trace elements.

Table 28. EMISSION FACTORS FOR ELECTRIC GENERATION EXTERNAL COMBUSTION

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
1.0.00.0.0	Electric generation	NA	NA	NA	NA	NA
1.1.00.0.0	External combustion	NA	NA	NA	NA	NA
1.1.10.0.0	Coal[b]	NA	NA	NA	NA	NA
1.1.11.0.0	Bituminous	NA	NA	NA	NA	NA
1.1.11.1.0	Pulverized dry	17A	38S	18	0.3	1
1.1.11.2.0	Pulverized wet	13A	38S	30	0.3	1
1.1.11.3.0	Cyclone	2A	38S	55	0.3	1
1.1.11.4.0	All stokers	13A	38S	15	1	2
1.1.12.0.0	Anthracite	NA	NA	NA	NA	NA
1.1.12.1.0	Pulverized dry	17A	38S	18	0.03	1
1.1.12.2.0	Pulverized wet	X	X	X	X	X
1.1.12.3.0	Cyclone	X	X	X	X	X
1.1.12.4.0	All stokers	2A	38S	18	0.2	2
1.1.13.0.0	Lignite	NA	NA	X	NA	NA
1.1.13.1.0	Pulverized dry	7A	30S	X	1	1
1.1.13.2.0	Pulverized wet	7A	30S	15	1	1
1.1.13.3.0	Cyclone	6A	30S	NA	1	1
1.1.13.4.0	All stokers	7A	30S	6	1	2
1.1.20.0.0	Petroleum	NA	NA	NA	NA	NA
1.1.21.0.0	Residual oil	NA	NA	NA	NA	NA
1.1.21.0.1	Tangential firing	8	157S	50	2	3
1.1.21.0.2	All other	8	157S	105	2	3
1.1.22.0.0	Distillate oil	NA	NA	NA	NA	NA
1.1.22.0.1	Tangential firing	8	157S	50	2	3
1.1.22.0.2	All other	8	157S	105	2	3
1.1.30.0.0	Gas[d]	NA	NA	NA	NA	NA
1.1.30.0.1	Tangential firing	10	0.6	300	1	17
1.1.30.0.2	All other	10	0.6	700	1	17

Table 28 (continued). EMISSION FACTORS FOR ELECTRIC GENERATION EXTERNAL COMBUSTION

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[a] Abbreviations used in the table have the following meanings

A = Multiply by weight percent ash

B = Multiply by weight percent sulfur

X = Fuel consumed in this combustion system is small, emission is assumed to be negligible.

NA = Emissions for this combustion system were calculated as the total of emissions from the appropriate subsystems

[b] The emission factors for coal give values in terms of pounds of pollutant per ton of coal burned.

[c] The emission factors for oil give values in terms of pounds of pollutant per 1000 gallons of oil burned.

[d] The emission factors for gas give values in terms of pounds of pollutant per 10^6 cubic feet of gas burned.

Particulates - Electricity generation by utilities accounts for 13 percent of the total man-made emissions of particles in the United States and 64 percent of the total particulate emissions from stationary combustion sources. These emissions occur after combustion gases pass through control devices such as electrostatic precipitators, cyclones, scrubbers, and filters that can eliminate up to 99 percent of the particulate mass loading.

Much of the discussion that follows deals with coal combustion because coal accounts for 98 percent of the particulate emissions from utilities. The discussion deals first with particulate loading before control devices and then with particulate emissions after control devices. It is divided further into sections dealing with total mass emissions and with emissions of fine particles, because while control devices are efficient for the largest particles they are less efficient for the fine (< 3 micron) particles.

Coal - The NEDS emission factors in Table 28 used to prepare Table 27 were obtained from Smith et al.[51] Diagrams from that reference are reprinted in Figures 5 through 9 for the various furnace types. The data were obtained via personal communications and via test data collected in the 1950's. A statistical summary of the data is presented in Table 29. The range of the data, the mean, the standard deviation, and the 90 percent confidence interval were calculated for all furnace types except the stoker for which there was insufficient data. The calculated 90 percent confidence intervals may be too small as they were based on the assumption that all the data values were independent.

Data on fine particulate loadings before control devices have been reported in two MRI studies.[52,53] The accuracy of these data is uncertain, however, because analytical techniques may have altered the original size distributions, and much of the fine particulate data were extrapolated from data on larger size ranges. For 300 pulverized coal-fired units fine-particles ranged from 4 to 22 percent of the total particulate mass, with a mean of 13 percent. For cyclone units, extrapolations indicate that fine particles accounted for 30 percent of the total. For stokers, fine particles ranged from 1 to 13 percent of the total, with a mean of 6 percent. The results for stokers are consistent with similar studies by GCA.[54]

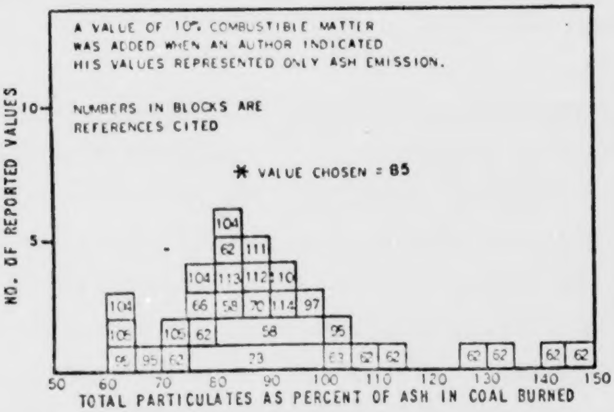

Figure 5. Total particulate emissions from dry-bottom pulverized coal-fired units (Reprinted from Reference 51)

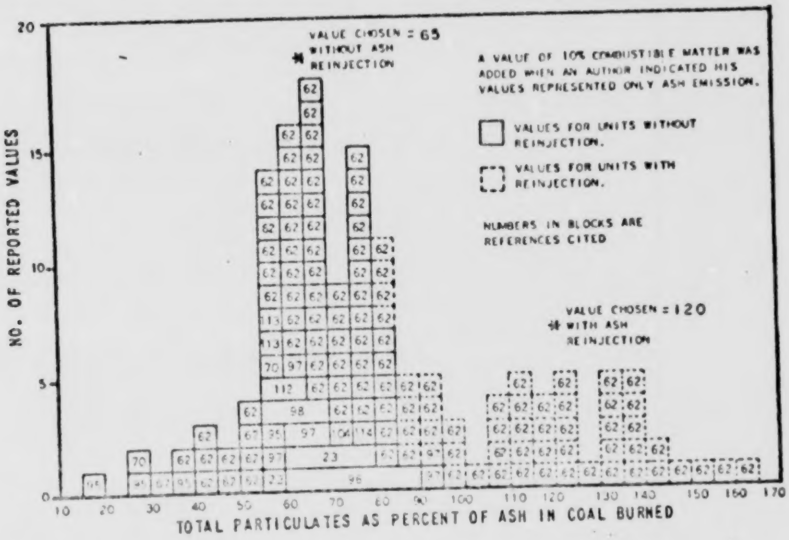

Figure 6. Particulate emissions from wet-bottom, pulverized coal-fired units (Reprinted from Reference 51)

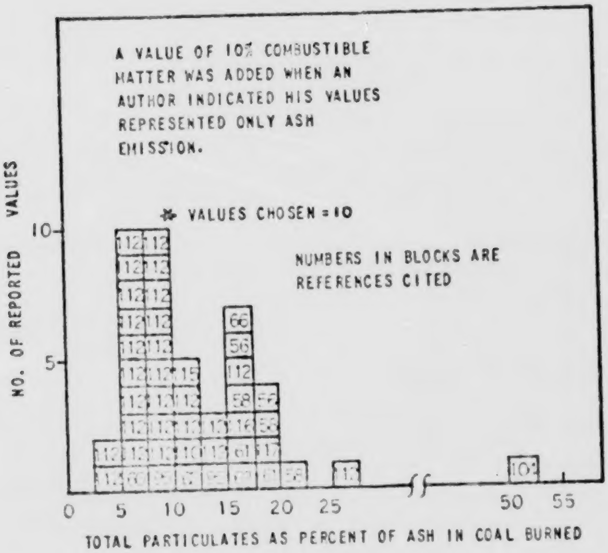

Figure 7. Particulate emissions from cyclone units (Reprinted from reference 51)

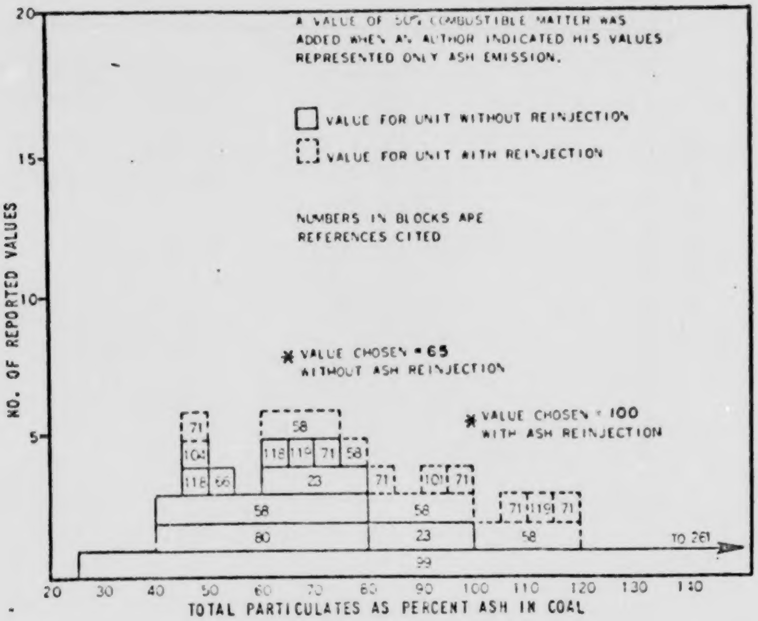

Figure 8. Particulate emissions from spreader stoker-fired units (Reprinted from Reference 51)

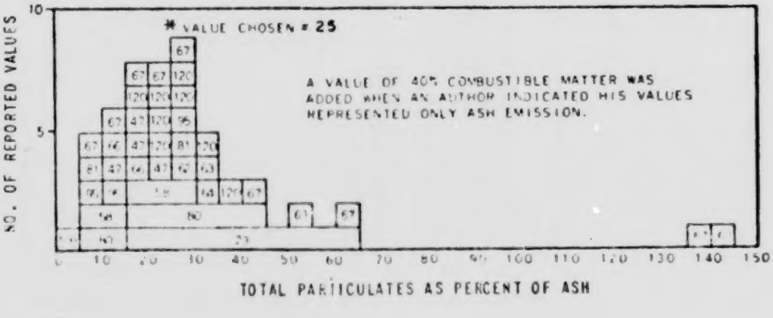

Figure 9. Particulate emissions from stoker-fired units (except spreader stokers) (Reprinted from Reference 51)

Table 29. PARTICULATE EMISSION FACTORS FOR COAL COMBUSTION WITHOUT CONTROL EQUIPMENT[a]

Type of unit	Pounds of particulate per ton of coal burned, values represent emissions before control equipment			Standard deviation[b]
	Reference	Total range	Mean and 90% confidence interval[b]	
Pulverized				
Dry bottom	17A	12A - 30A	18.2A ± 6.7A	4.1
Wet bottom without fly ash reinjection	13A	3A - 19A	12.9A ± 4.4A	2.7
Wet bottom with fly ash reinjection	24A	16A - 33A	23.1A ± 7.1A	4.3
Cyclone	2A	0.5A - 10.5A	2.4A ± 2.6A	1.6
Spreader stoker				
Without fly ash reinjection	13A	5A - 52A	-	-
With fly ash reinjection	20A	9A - 24A	-	-
All other stokers	5A	0A - 29A	-	-

[a] Based on reference 51 except as indicated.

[b] These values were calculated under the assumption that the reported data values were independent.

Estimates of the average efficiency of particulate control devices on coal-fired utility boilers are listed in Table 30, along with estimates of particulate emissions after control. The data reported in the first three columns were obtained in MRI[55] telephone surveys conducted in 1968 and 1969. Estimates derived by GCA from FPC Form 67 magnetic tape data are listed in the last column. The differences between the MRI estimates and our estimates based on the FPC data are small except for the cyclone type. The MRI estimates were used in Table 27. The accuracy of these estimates of average efficiency is uncertain because of differences between design and operating efficiency. One study[56] reported an average design efficiency of 98.2 percent for 14 high efficiency units and an average operating efficiency of 89.3 percent. Emissions estimated using the design efficiency are a factor of 5 less than emissions estimated using the operating efficiency. Another study[57] of 12 units fitted with electrostatic precipitators reported an average design efficiency of 99.5 percent versus an average operating efficiency of 95.7 percent. Here emissions estimates based on design efficiency are a factor of 9 less than those based on operating efficiency.

Table 30. TOTAL MASS EFFICIENCY OF PARTICULATE CONTROL DEVICES IN COAL-FIRED UTILITY BOILERS

Boiler type	Control device efficiency[a] C_c	Application of control[b] C_a	U.S. average efficiency $C_m = C_c \cdot C_a$	FPC data U.S. average efficiency[c]
Pulverized	0.92	0.97	0.89	0.89
Cyclone	0.91	0.71	0.65	0.88
Stoker	0.80	0.87	0.70	0.65

[a] The data in this table were obtained from utilities accounting for one-half of the total U.S. utility consumption of coal. C_c is the fraction collected of the total particulate mass entering control devices.[55]

[b] C_a is the fraction of utility boilers equipped with particulate control devices.[55]

[c] These values were calculated from Federal Power Commission Form 67 data for the 1972 reporting year.

Estimates of the average fine particulate efficiency of control devices on coal-fired utility boilers are listed in Table 31. The data reported in the first three columns were obtained by MRI[55] from studies of a variety of particulates only some of which were derived from coal. The efficiency data reported by MRI are shown in Figure 10. Much of these data was published originally by Stairmand.[58] The data in the last column of Table 31 show the relationship between total particulate and fine particulate emissions used in Table 27. Additional data on fine particulates are shown in Figure 11. Curve 1 is a composite of three field tests reported by SRI[59] on high efficiency electrostatic precipitators connected to pulverized coal-fired units; curve 2 is a composite of 22 tests of a fabric filter reported by GCA[54] on a stoker. The MRI data from Figure 10 are also plotted for comparison.

Table 31. FINE PARTICULATE EFFICIENCY OF PARTICULATE CONTROL DEVICES IN COAL-FIRED UTILITY BOILERS[a]

Boiler type	Control device efficiency[b] C_c	Application of control[c] C_a	U.S. average efficiency $C_m = C_c \cdot C_a$	Fine particulate fraction[d] F_p
Pulverized	0.75	0.97	0.73	0.35
Cyclone	0.55	0.71	0.39	0.52
Stoker	0.32	0.87	0.28	0.14

[a] The data in this table were obtained from utilities accounting for one-half of the total U.S. utility consumption of coal.

[b] C_c is the fraction collected of the fine particulate mass entering control devices. Part of the data is from test results and part is from reported design efficiencies.

[c] C_a is the fraction of utility boilers equipped with particulate control devices.

[d] F_p is the fraction of the total particulate mass emission that is fine (<3 micron) particulates and was derived from the ratio of fine particulates to total mass.

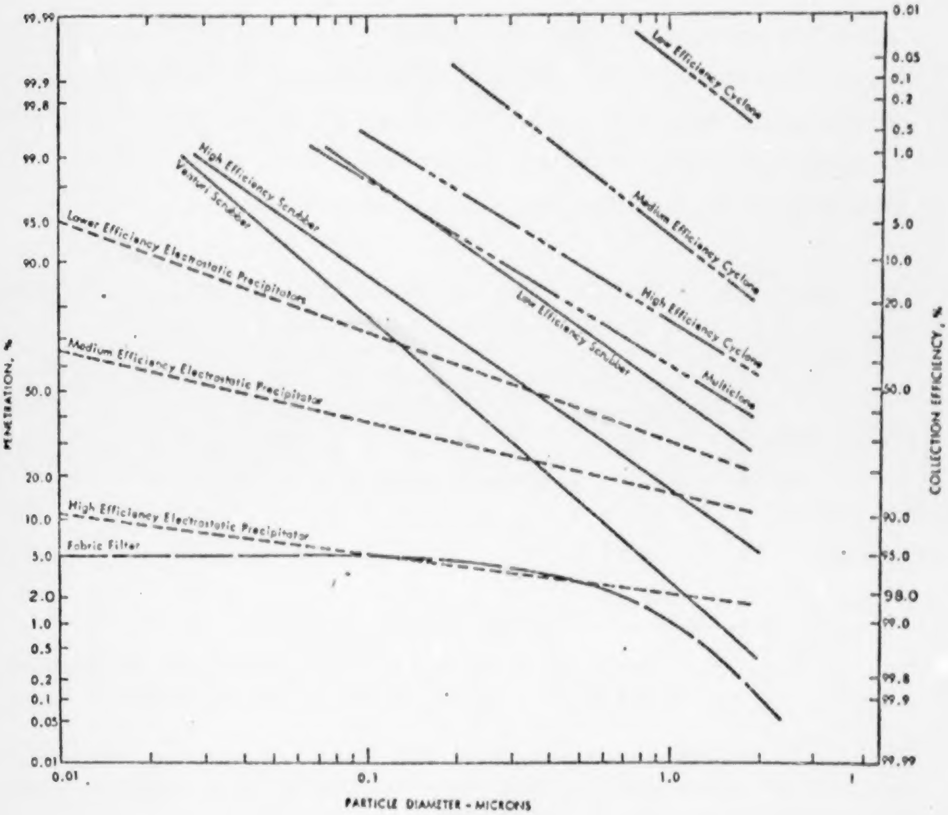

Figure 10. Control device efficiencies for a variety of industrial particulates (Reference 55)

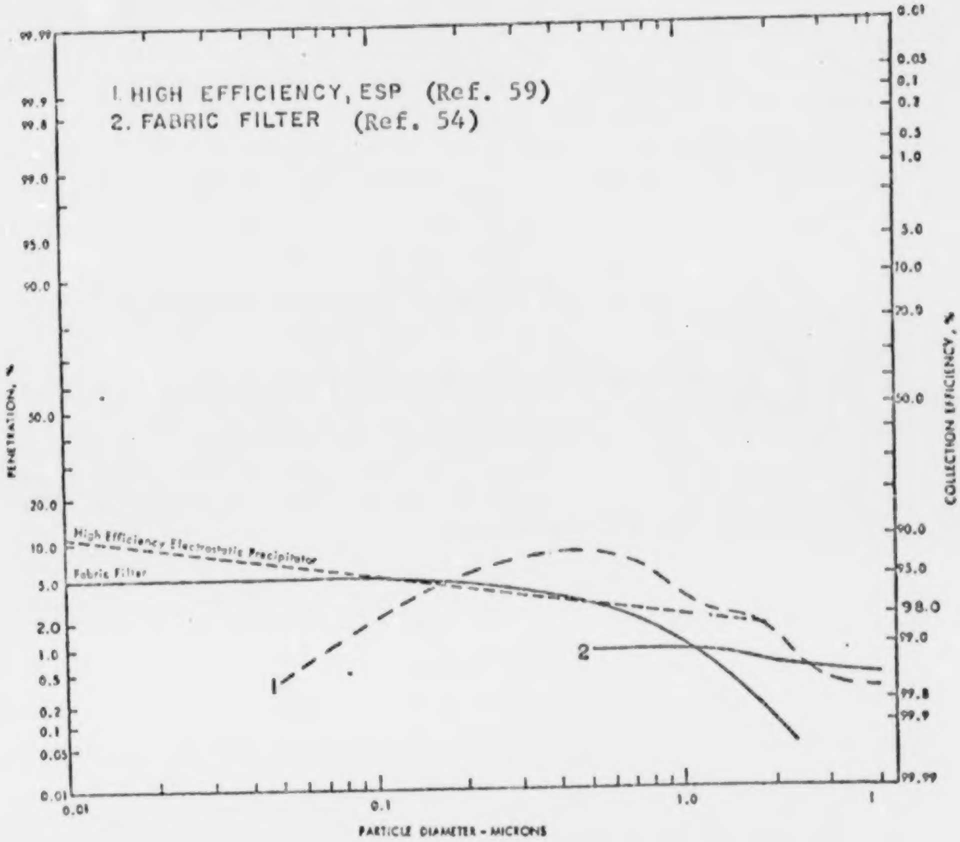

Figure 11. Control device efficiencies for recent field test results of coal-fired boilers (curves 1 and 2)

Oil/gas - The emission factors listed in Table 28 were used to estimate loadings before particulate control. The efficiencies shown in Table 32 were used to estimate emissions after particulate control.

Table 32. EFFICIENCIES OF PARTICULATE CONTROL DEVICE IN OIL- AND GAS-FIRED UTILITY BOILERS

Fuel type	Control device efficiency[a] C_a	Application of control[b] C_a	U.S. average efficiency $C_m = C_c \cdot C_a$	Fine particulate fraction[c] F_p
Oil	0.50	0.20	0.10	0.90
Gas	-	0	0	0.90

[a] C_c is the fraction collected of the total particulate mass entering control devices.

[b] C_a is the fraction of utility boilers equipped with particulate control devices.

[c] F_p is the fraction of the total particulate mass emission that is fine (<3 micron) particulates and was derived from the ratio of fine particulates to total mass.

Sulfur Oxides (SO_x) - Total man made SO_x emissions amounted to 31 million tons in 1974. Of this total stationary fossil fuel combustion sources accounted for 22 million tons. Electric power plants contributed 16 million tons or 52 percent of the annual SO_x emissions. Coal combustion represented 87 percent of utility generated SO_x emissions. Between 1960 and 1970 SO_x emissions increased at the rate of 4 percent per year.[61]

About 98 percent of the SO_x emitted from combustion sources is in the form of SO_2. For the combustion of anthracite and bituminous coals, as well as fuel oils, evidence in the literature[62,63] suggests that the conversion of sulfur compounds in these fuels to SO_2 is 90 to 100 percent complete. Sulfur retention in anthracite and bituminous coal ash is generally low. In a Bureau of Mines ashing study of anthracite coals[64] sulfur retention ranged from about 1 percent to almost 15 percent at the low ashing temperature (750°C) and was substantially less than 1 percent at the high ashing temperature (1200°C). In another ashing study involving bituminous coal[65] sulfur retention was less than 5 percent.

There is some evidence that sulfur in coal of high alkali ash content tends to concentrate in the ash during combustion and that this sulfur retention occurs roughly equally for pyritic and organic sulfur.[66,67] Most of the evidence is for low rank (lignite) coals which generally have high alkali content. Studies involving North Dakota lignite have received considerable attention in the literature. In two independent pulverized firing studies in 20 MW to 215 MW utility boilers[66,67] sulfur retention ranged from 10 percent to 40 percent. In two ashing studies[65,68] conducted in accordance with ASTM-approved procedures 60 percent to 90 percent sulfur retention was observed. In addition, several studies[65-72] have shown that the addition of lime, limestone, or dolomite directly into a furnace can reduce SO_x emissions, although boiler operating problems have been serious.[72]

The degree of SO_3 formation, usually 1 to 2 percent of total SO_x, is dependent upon combustion conditions.[61] In general, the leaner the fuel mixture the more SO_3 relative to SO_2 is formed. In addition, SO_3 formation is a function of the age of the combustion device, boiler design, and method of firing.

Nitrogen Oxides (NO_x) - According to a recent National Academy of Sciences Study[61] national nitrogen oxide emissions have grown at an average rate of over 4 percent per year for the last 3 decades. At present, stationary source fuel combustion accounts for about 65 percent of all U.S. man-made nitrogen oxide emissions. Projections of future nitrogen oxide emissions demonstrate that, if present statutory standards are adhered to, stationary sources will contribute an increasing percentage of total nitrogen oxide emissions through 1990. The nitrogen oxide emission rate per Btu produced is greater from coal than from either oil or natural gas.

Nitrogen oxides (NO_x) are formed in the high temperature region of the furnace; i.e., in the flame zone, by two mechanisms. The first mechanism, termed "thermal" fixation, involves the reaction of atmospheric oxygen and nitrogen. These react in radical chain reactions. The second mechanism, termed "fuel-N conversion," involves the oxidation of fuel contaminants that contain nitrogen. These contaminants are derivations of such compounds as pyridine and quinoline. Generally, more than 90 percent of the NO_x emitted to the atmosphere is NO with the remainder being NO_2.

The amount of NO_x formed in the furnace is dependent upon several operating variables.[79] One of these is excess air. For a given furnace temperature distribution the amount of NO_x formed decreases as the excess air decreases. This decrease occurs because of a decrease in the oxygen concentration in the high temperature flame zone where the NO_x is formed. The influence of temperature on NO_x emissions is more complex. Decreases in temperature are associated with decreases in NO_x emissions. However, the thermal fixation reactions are more temperature-dependent than the fuel-N conversion reactions. Therefore, for a fixed value of excess air, decreases in temperature cause emissions to decrease from thermal fixation rather than from fuel-N conversion.

Thus emissions of NO_x can be minimized by reducing the oxygen content and temperature in the flame zone of the furnace. Reductions in the oxygen content reduce emissions of both fuel NO_x and thermal NO_x whereas reductions in temperature produce significant reductions only in thermal NO_x. Methods that have been used to reduce temperature include: (a) injection of cooled combustion products, steam, or water into the flame zone; (b) reduction of the temperature to which combustion air is preheated; (c) extraction of heat from the flame zone; and (d) reduced furnace load.

Methods of reducing oxygen content in the flame zone include reducing the overall excess air and reducing the excess air for some burners without reducing the overall excess air (staged combustion). Low excess air firing, staged combustion, flue-gas recirculation, reduced furnace load, water or steam injection, and reduced air preheat are control techniques that have been successfully demonstrated on utility boilers, although the latter two methods do reduce thermal efficiency. Using combinations of the techniques listed above, an average reduction in nitrogen oxide emissions of 37 percent has been achieved for coal-fired utility boilers, 48 percent for oil-fired boilers, and 60 percent for gas-fired boilers.[73]

Coal - Data on NO_x emissions from 53 coal-fired utility boilers are presented in Table 33. Emission factor data in terms of pounds of NO_2 per million Btu are summarized in Table 34. The data in Table 34 correspond to full load operation without modifications for NO_x reduction. The average NO_2 emission for the pulverized coal-fired units, 0.68 pounds per million Btu, was near the new source performance standard of 0.7 $lb/10^6$ Btu. Excess air ranged from 5 to 50 percent in the reported data for normal operation. This compares with a range of from 5 percent to 25 percent which is typical for NO_x control strategies.[23,78] Reduction below 15 percent is accomplished at the risk of increased emissions of CO and unburned hydrocarbons and at the risk of increased slagging and corrosion.[73]

Although the data in Table 33 on cyclone boilers are scanty, it is clear that NO_x emissions from the cyclone boilers are greater than from the pulverized coal-fired boilers. This observation has been made by others also.[73] The emissions from pulverized units are greater than from stokers. All of these trends are consistent with the fact that cyclones have the highest heat release rates and furnace temperatures and that stokers have the lowest.

The emissions from the wet bottom boilers are higher than from the dry bottom boilers. Generally, wet bottom boilers operate at higher temperatures than dry bottom boilers. These differences in temperature are

Table 33. NO_x TEST DATA FROM COAL-FIRED UTILITY BOILERS[73]

Boiler No.	No. of burners	Boiler size, MW	Boiler load, MW	Boiler type[a]	Wet dry[e]	Firing pattern[b]	Nitrogen content, %	Excess air, %	O_2 in flue gas, %	NO_x control[c]	NO_x emissions		No. of tests	Analysis method[d]	Test date	Test location	Ref.
											lb/10^6 Btu	lb/ton					
SS-1	NA	13	13	Stok.	D	NA	1.4	44.8	7.0	NA	0.76	21.1	3-4	PSA	-	-	74
SS-1	NA	13	10.5	Stok.	D	NA	1.4	51.1	7.2	NA	0.68	18.9		PSA	-	-	74
C-1	NA	120	120	Cyc.	W	NA	1.4	42.0	6.3	NA	2.2	61.2	3-4	PSA	-	-	74
C-1	NA	120	90	Cyc.	W	NA	1.4	46.2	6.8	NA	1.8	50.1		PSA	-	-	74
HO-1	-	13	13	Pulv.	W	H	1.6	40.7	6.1	NA	0.59	15.6	3-4	PSA	-	-	74
HO-1	-	13	9.5	Pulv.	W	H	1.6	43.7	6.5	NA	0.56	14.8		PSA	-	-	74
NAS-1	7	6	4.8	Stok.	-	NA	-	-	-	NA	0.327	-	-	-	-	-	61
NAS-1	7	6	4.8	Sto .	-	NA	-	-	-	LEA	0.263	-	-	-	-	-	61
NAS-2	7	6	4.6	Stok.	-	NA	-	-	-	NA	0.314	-	-	-	-	-	61
NAS-2	7	6	4.6	Stok.	-	NA	-	-	-	LEA	0.277	-	-	-	-	-	61
NAS-3	2	13.5	11	Stok.	-	NA	-	-	-	NA	0.518	-	-	-	-	-	61
NAS-3	2	13.5	11	Stok.	-	NA	-	-	-	LEA	0.469	-	-	-	-	-	61
NAS-4	1	5	4	Stok.	-	NA	-	-	-	NA	0.651	-	-	-	-	-	61
NAS-4	1	5	4	Stok.	-	NA	-	-	-	LEA	0.462	-	-	-	-	-	61
NAS-5	1	7.5	6.3	Stok.	-	NA	-	-	-	NA	0.651	-	-	-	-	-	61
NAS-5	1	7.5	6.3	Stok.	-	NA	-	-	-	LEA	0.542	-	-	-	-	-	61
NAS-6	8	22.5	18.1	Pulv.	-	-	-	-	-	NA	0.529	-	-	-	-	-	61
NAS-6	8	22.5	18.1	Pulv.	-	-	-	-	-	LEA	0.504	-	-	-	-	-	61
NAS-7	5	21	12	Stok.	-	NA	-	-	-	NA	0.774	-	-	-	-	-	61
NAS-7	5	21	12	Stok.	-	NA	-	-	-	LEA	0.659	-	-	-	-	-	61
NAS-8	6	23	16.2	Stok.	-	NA	-	-	-	NA	0.766	-	-	-	-	-	61
NAS-8	6	23	16.2	Stok.	-	NA	-	-	-	LEA	0.504	-	-	-	-	-	61
NAS-9	6	50	40	Pulv.	-	-	-	-	-	NA	0.812	-	-	-	-	-	61
NAS-10	2	51.3	32	Cyc.	-	NA	-	-	-	NA	1.120	-	-	-	-	-	61
NAS-10	2	51.3	32	Cyc.	-	NA	-	-	-	LEA	1.039	-	-	-	-	-	61
NAS-11	1	1	0.8	Stok.	-	NA	-	-	-	NA	0.382	-	-	-	-	-	61
NAS-12	1	1	0.8	Stok.	-	NA	-	-	-	NA	0.484	-	-	-	-	-	61
NAS-13	8	32.5	26	Pulv.	-	-	-	-	-	NA	0.678	-	-	-	-	-	61
J-1	-	576	460	Pulv.	-	T	-	-	-	NA	0.57	-	-	-	-	-	75
J-1	-	576	460	Pulv.	-	T	-	-	-	SF	0.34	-	-	-	-	-	75
CE-1	-	52	52	Pulv.	-	T	-	-	-	NA	0.49	-	-	PSA	-	-	76
CE-2	-	100	100	Pulv.	-	T	-	-	-	NA	0.56	-	-	PSA	-	-	76
CE-2	-	100	80	Pulv.	-	T	-	-	-	SF	0.21	-	-	PSA	-	-	76
CE-3	-	110	110	Pulv.	-	T	-	-	-	NA	0.49	-	-	PSA	-	-	76
CE-4	-	122	122	Pulv.	-	T	-	-	-	NA	0.50	-	-	PSA	-	-	76
CE-5	-	170	170	Pulv.	-	T	-	-	-	NA	0.76	-	-	PSA	-	-	76
CE-5	-	170	157	Pulv.	-	T	-	-	-	SF	0.60	-	-	PSA	-	-	76
CE-6	-	206	206	Pulv.	-	T	-	-	-	NA	0.71	-	-	PSA	-	-	76

Table 33 (continued). NO_x TEST DATA FROM COAL-FIRED UTILITY BOILERS[73]

Boiler No.	No. of burners	Boiler size, MW[a]	Boiler load, MW	Boiler type[b]	Wet dry[c]	Firing pattern[d]	Nitrogen content, %	Excess air, %	O_2 in flue gas, %	NO_x control[e]	NO_x emissions[f]		No. of tests	Analysis method[f]	Test date	Test location	Ref.
											lb/10^6 Btu	lb/ton					
WC-6	16	125	125	Pulv.	D	FB	1.29-1.72	-	3.4	NA	0.84	20.4	41	IR,UV,CL	4/12/72	Widows Creek	73
WC-6	16	125	123	Pulv.	D	FB	1.29-1.72	-	2.0	Low NO_xI	0.50	12.2		IR,UV,CL	to	Widows Creek	73
WC-6	16	125	100	Pulv.	D	FB	1.29-1.72	-	2.7	Low NO_xII	0.39	9.5		IR,UV,CL	5/4/72	Widows Creek	73
DJ-2	18	105	101	Pulv.	D	FB	0.77-0.86		5.0	NA	0.60	9.4	14	IR,UV,CL	7/27/73 to	Dave Johnston	73
DJ-2	18	105	99	Pulv.	D	FB	0.77-0.86	-	5.2	Low NO_xI	0.28	4.4		IR,UV,CL	8/1/73	Dave Johnston	73
EDE-2	16	256	253	Pulv.	W	FB	1.18-1.42	-	3.5	NA	0.93	19.5	19	IR,UV,CL	6/11/63	E.D. Edwards	73
EDE-2	16	255	256	Pulv.	W	FB	1.18-1.42	-	1.6	Low NO_xI	0.48	10		IR,UV,CL	to	E.D. Edwards	73
EDE-2	16	256	221	Pulv.	W	FB	1.18-1.42	-	3.0	Low NO_xII	0.39	8.2		IR,UV,CL	6/15/73	E.D. Edwards	73
C-6	16	320	350	Pulv.	D	FB	1.33-1.43	-	3.3	NA	1.11	28.3	22	IR,UV,CL	12/6/72	Crist	73
C-6	16	320	320	Pulv.	D	FB	1.33-1.43	-	2.2	Low NO_xI	0.73	18.6		IR,UV,CL	to	Crist	73
C-6	16	320	260	Pulv.	D	FB	1.33-1.43	-	3.5	Low NO_xII	0.70	17.9		IR,UV,CL	3/20/73	Crist	73
LO-1	20	218	219	Pulv.	D	H	1.03-1.12	-	3.9	NA	0.76	16.4	13	IR,UV,CL	7/6/73	Leland Olds	73
LO-1	20	218	218	Pulv.	D	H	1.03-1.12	-	2.8	Low NO_xI	0.50	10.8		IR,UV,CL	to	Leland Olds	73
LO-1	20	218	185	Pulv.	D	H	1.03-1.12	-	2.2	Low NO_xII	0.34	7.3		IR,UV,CL	7/12/73	Leland Olds	73
HB-3	40	480	490	Pulv.	W	H	1.40-1.93	-	3.5	NA	0.95	25	51	IR,UV,CL	5/22/73	Harllee Branch	73
HB-3	40	480	473	Pulv.	W	H	1.40-1.93	-	1.4	Low NO_xI	0.62	16.4		IR,UV,CL	to	Harllee Branch	73
HB-3	40	480	400	Pulv.	W	H	1.40-1.93	-	1.6	Low NO_xII	0.48	12.7		IR,UV,CL	7/28/72	Harllee Branch	73
FC-4	54	800	800	Pulv.	D	H	1.23-1.31	-	5.0	NA	1.24	22	26	IR,UV,CL	11/2/72	Four Corners	73
FC-4	54	800	794	Pulv.	D	H	1.23-1.31	-	3.2	Low NO_xI	0.65	11.5		IR,UV,CL	to	Four Corners	73
FC-4	54	800	600	Pulv.	D	H	1.23-1.31	-	3.0	Low NO_xII	0.60	10.6		IR,UV,CL	11/21/72	Four Corners	73
B-3	48	250	250	Pulv.	-	T	1.30-1.59	-	3.1	NA	0.55	13.2	8	IR,UV,CL	3/23/73	Barry	73
B-3	48	250	248	Pulv.	-	T	1.30-1.59	-	1.3	Low NO_xI	0.41	9.8		IR,UV,CL	3/23/73	Barry	73
N-3	20	330	334	Pulv.	D	T	1.47-1.65	-	4.2	NA	0.71	14.6	26	IR,UV,CL	9/13/72	Naughton	73
N-3	20	330	310	Pulv.	D	T	1.47-1.65	-	2.3	Low NO_xI	0.29	6		IR,UV,CL	to	Naughton	73
N-3	20	330	256	Pulv.	D	T	1.47-1.65	-	3.0	Low NO_xII	0.26	5.4		IR,UV,CL	10/10/72	Naughton	73
B-4	20	350	350	Pulv.	-	T	1.30-1.59	-	4.4	NA	0.55	13.2	46	IR,UV,CL	1/19/73	Barry	73
B-4	20	350	300	Pulv.	-	T	1.30-1.59	-	2.4	Low NO_xI	0.36	8.6		IR,UV,CL	to	Barry	73
B-4	20	350	186	Pulv.	-	T	1.30-1.59	-	2.2	Low NO_xII	0.25	6		IR,UV,CL	2/23/73	Barry	73
DJ-4	28	348	306	Pulv.	D	T	0.77-0.86	-	4.2	NA	0.53	8.3	6	IR,UV,CL	8/869/73	Dave Johnston	73
DJ-4	28	348	304	Pulv.	D	T	0.77-0.86	-	3.3	Low NO_xI	0.51	8		IR,UV,CL	8/869/73	Dave Johnston	73
BB-2	24	350	370	Pulv.	W	O(turbo)	1.26-1.41	-	2.8	NA	0.80	19.1	14	IR,UV,CL	3/5/73	Big Bend	73
BB-2	24	350	370	Pulv.	W	O(turbo)	1.26-1.41	-	1.4	Low NO_xI	0.53	12.7		IR,UV,CL	to	Big Bend	73
BB-2	24	350	300	Pulv.	W	O(turbo)	1.26-1.41	-	1.8	Low NO_xII	0.45	10.7		IR,UV,CL	3/12/73	Big Bend	73
V-1	16	97	97	Pulv.	D	V	1.4	45.3	6.4	NA	0.55	13	3-4	PSA	-	-	74
V-1	16	97	72	Pulv.	D	V	1.4	48.8	7.0	NA	0.31	7.3		PSA	-	-	74
T-1	16	85	85	Pulv.	D	T	1.3-1.4	29.1	4.8	NA	0.71	17.1	3-4	PSA	-	-	74
T-1	16	85	62	Pulv.	D	T	1.3-1.4	25.6	4.4	NA	0.57	13.8		PSA	-	-	74
FW-1	24	80	80	Pulv.	D	FB	1.5	35.5	5.6	NA	0.95	24.9	3-4	PSA	-	-	74
FW-1	24	80	55	Pulv.	D	FB	1.5	37.7	5.8	NA	0.74	19.4		PSA	-	-	74

Table 33 (continued). NO_x TEST DATA FROM COAL-FIRED UTILITY BOILERS[73]

Boiler No.	No. of burners	Boiler size, MW	Boiler load, MW	Boiler[a] type	Wet[e] dry	Firing[b] pattern	Nitrogen content, %	Excess air, %	O_2 in flue gas, %	NO_x[c] control	NO_x emissions		No. of tests	Analysis method[d]	Test date	Test location	Ref.
											lb/10^6 Btu	lb/ton					
CE-7	-	215	215	Pulv.	-	T	-	-	-	NA	0.63	-	-	PSA	-	-	76
CE-7	-	215	158	Pulv.	-	T	-	-	-	SF	0.32	-	-	PSA	-	-	76
CE-8	-	250	250	Pulv.	-	T	-	-	-	NA	0.74	-	-	PSA	-	-	76
CE-9	-	250	250	Pulv.	-	T	-	-	-	NA	0.56	-	-	PSA	-	-	76
CE-10	-	265	265	Pulv.	-	T	-	-	-	NA	0.84	-	-	PSA	-	-	76
CE-11	-	370	370	Pulv.	-	T	-	-	-	NA	0.67	-	-	PSA	-	-	76
CE-12	-	375	375	Pulv.	-	T	-	-	-	NA	0.90	-	-	PSA	-	-	76
CE-13	-	378	378	Pulv.	-	T	-	-	-	NA	0.84	-	-	PSA	-	-	76
CE-14	-	426	426	Pulv.	-	T	-	-	-	NA	0.70	-	-	PSA	-	-	76
CE-15	-	485	485	Pulv.	-	T	-	-	-	NA	0.56	-	-	PSA	-	-	76
CE-16	-	565	565	Pulv.	-	T	-	-	-	NA	0.67	-	-	PSA	-	-	76
CE-16	-	565	395	Pulv.	-	T	-	-	-	SF	0.41	-	-	PSA	-	-	76
B-1	-	125	127	Pulv.	-	T	1.4	26	-	NA	0.61	-	-	PSA	-	-	77
B-1	-	125	127	Pulv.	-	T	1.4	18	-	NA	0.52	-	-	PSA	-	-	77
B-1	-	125	127	Pulv.	-	T	1.4	6	-	NA	0.31	-	-	PSA	-	-	77
B-1	-	125	142	Pulv.	-	T	1.4	9.5	-	NA	0.38	-	-	PSA	-	-	77
B-1	-	125	112	Pulv.	-	T	1.4	37.5	-	NA	0.57	-	-	PSA	-	-	77
B-1	-	125	112	Pulv.	-	T	1.4	17.5	-	NA	0.38	-	-	PSA	-	-	77
B-1	-	125	112	Pulv.	-	T	1.4	18	-	SF	0.29	-	-	PSA	-	-	77

[a] Pulv. - Pulverized
Cyc. - Cyclone
Stok. - Stoker

[b] H - Horizontally opposed
FB - Front or back wall
T - Trangential
O - Other
V - Vertical

[c] Low NO_xI - An optimized combination of staged firing and low excess air.
Low NO_xII - The same as Low NO_xI with reduced load.
LEA - Low excess air
SF - Staged firing

[d] IR - Infrared
UV - Ultraviolet
CL - Chemiluminescent
PSA - Phenoldisulfonic acid

[e] The boilers tested by Bartok[12] were classified as wet or dry by using FPC data.[9]

[f] 100 MW is approximately equal to 1040 x 10^6 Btu/hr, the exact equivalency depending on the efficiency of the unit.

NA - Not applicable
- - Unknown

Table 34. NO_x EMISSIONS FROM COAL-FIRED UTILITY BOILERS WITHOUT CONTROL AND AT FULL LOAD - TEST DATA SUMMARY

	NO_x emissions - $lb/10^6$ Btu			
	Number of boilers	Mean	Standard deviation	90 percent confidence interval
Pulverized	41	0.68	0.19	$\pm$ 0.31
Stokers	11	0.57	0.18	$\pm$ 0.30
Cyclones	2	1.66	0.76	-
Pulverized dry	13	0.74	0.25	$\pm$ 0.41
Pulverized wet	4	0.82	0.17	-
Pulverized unknown	24	-	-	-
P.D. tangential[a]	3	0.60	0.09	-
P.D. horizontally opposed[a]	2	1.00	0.34	-
P.D. front wall[a]	4	0.88	0.21	-
P.D. vertical[a]	1	0.55	-	-
P.W. tangential[b]	0	-	-	-
P.W. horizontally opposed[b]	2	0.77	0.25	-
P.W. front wall[b]	1	0.93	-	-
P.W. vertical[b]	0	-	-	-
All pulverized tangential	23	0.64	0.12	$\pm$ 0.20
All pulverized horizontally opposed	4	0.89	0.28	-
All pulverized front wall	5	0.89	0.19	-
All pulverized vertical	1	0.55	-	-

[a] Pulverized dry.

[b] Pulverized wet.

shown in Figure 12 in terms of higher heat release rates and furnace exit temperatures.

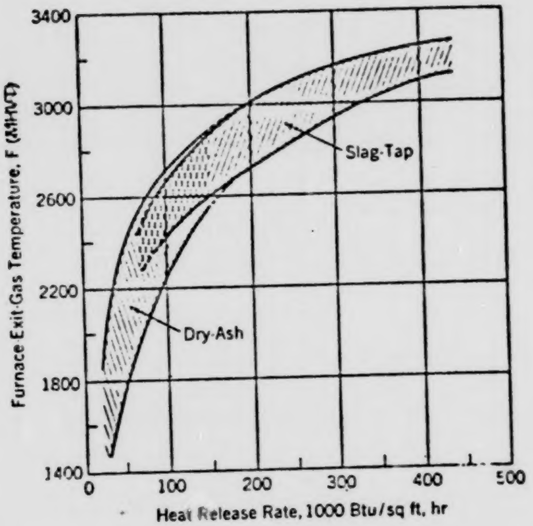

Figure 12. General range of furnace-exit-gas temperature for dry ash and slag-tap pulverized coal-firing (Reprinted from reference 78)

The emissions from the tangentially-fired boilers are generally lower than the rest. This is also consistent with temperature differences; the lowest temperatures are found in the tangentially-fired units.[79]

The data in Table 33 were examined for the dependence of NO_x emissions on boiler size. The relationship is shown in Figure 13 in which the distinction is made between pulverized tangential and pulverized other than tangential-firing patterns. No dependence is apparent. The data in Table 33 were also used to calculate emission factors in terms of pounds of NO_2 emitted per ton of coal burned. These emission factors compare with the EPA emission factors as follows:

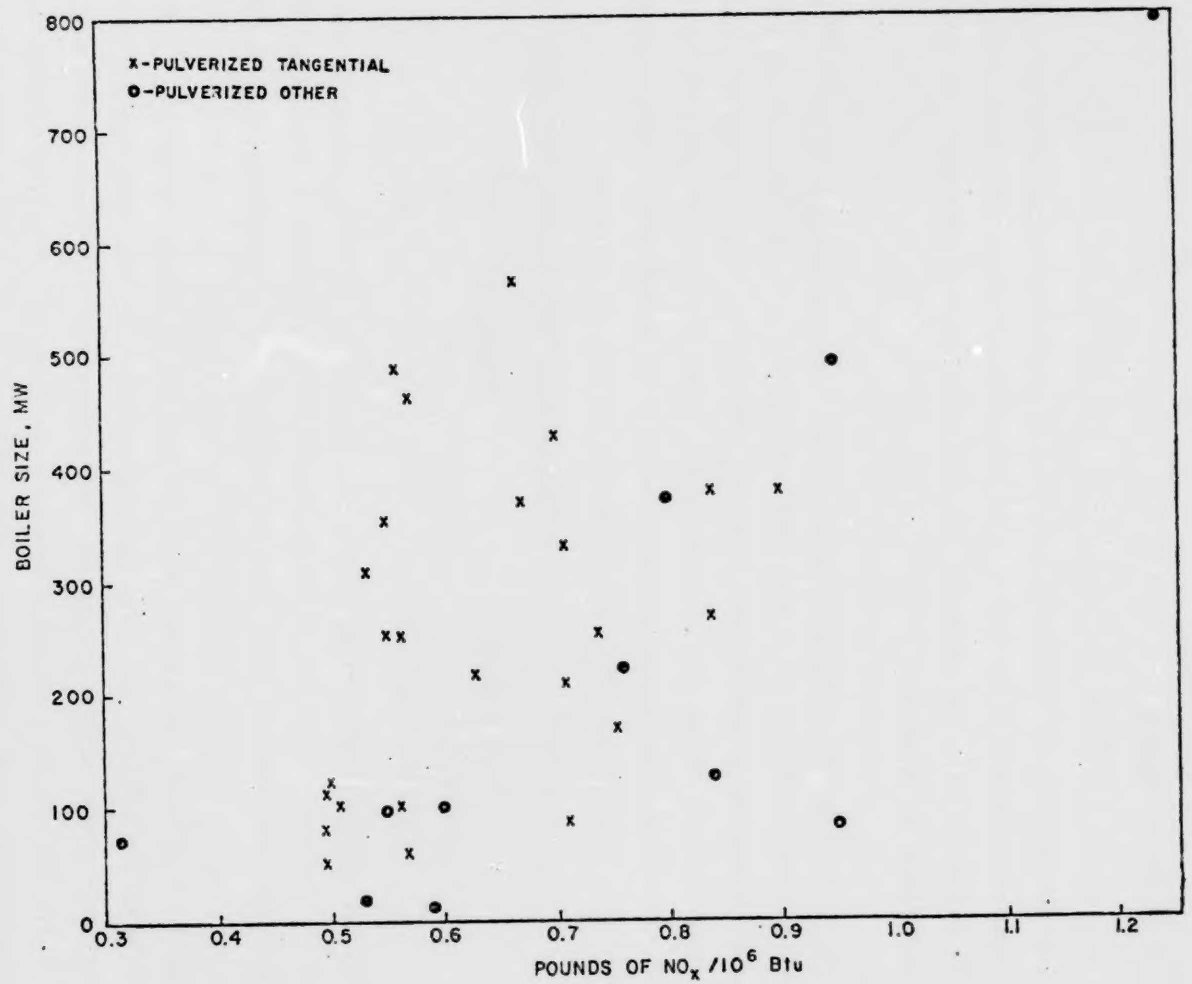

Figure 13. Test data of NO_x emissions from coal-fired utility boilers

	Emission factor (lb NO_2/ton coal)	
Boiler type	Table 33	EPA[9]
Pulverized	15	18
Stoker	13	15
Cyclone	37	55

For the pulverized and stoker-fired units the difference between emission factors is about 15 percent. For the cyclone units the difference is 30 percent. The EPA emission factors were used to estimate the stack emissions in Table 27.

Oil - Data on NO_x emissions from 31 oil-fired utility boilers[61,80] are presented in Figure 14. The data correspond to full load operation without combustion modifications for NO_x reduction. The average NO_x emissions for the tangentially-fired units were 0.27 lb/10^6 Btu; the average NO_x emissions for the other units were 0.55 lb/10^6 Btu. These emission factors compare with the EPA emission factors as follows:

	Emission factor (lb NO_2/10^3 gal)	
Firing type	Figure 14	EPA[9]
Tangential	40	50
Other than tangential	81	105

For the tangentially-fired units the difference between emission factors is 20 percent. For the other units the difference is 25 percent. The EPA emission factors were used to estimate the stack emissions in Table 27.

Gas - Data on NO_x emissions from 28 gas-fired utility boilers[61,80] are presented in Figure 15. The data correspond to full load operation without combustion modifications for NO_x reduction. The average NO_x emissions for the tangentially-fired units were 0.27 lb/10^6 Btu; the average NO_x emissions for the other units were 0.81 lb/10^6 Btu. The data in Figure 15

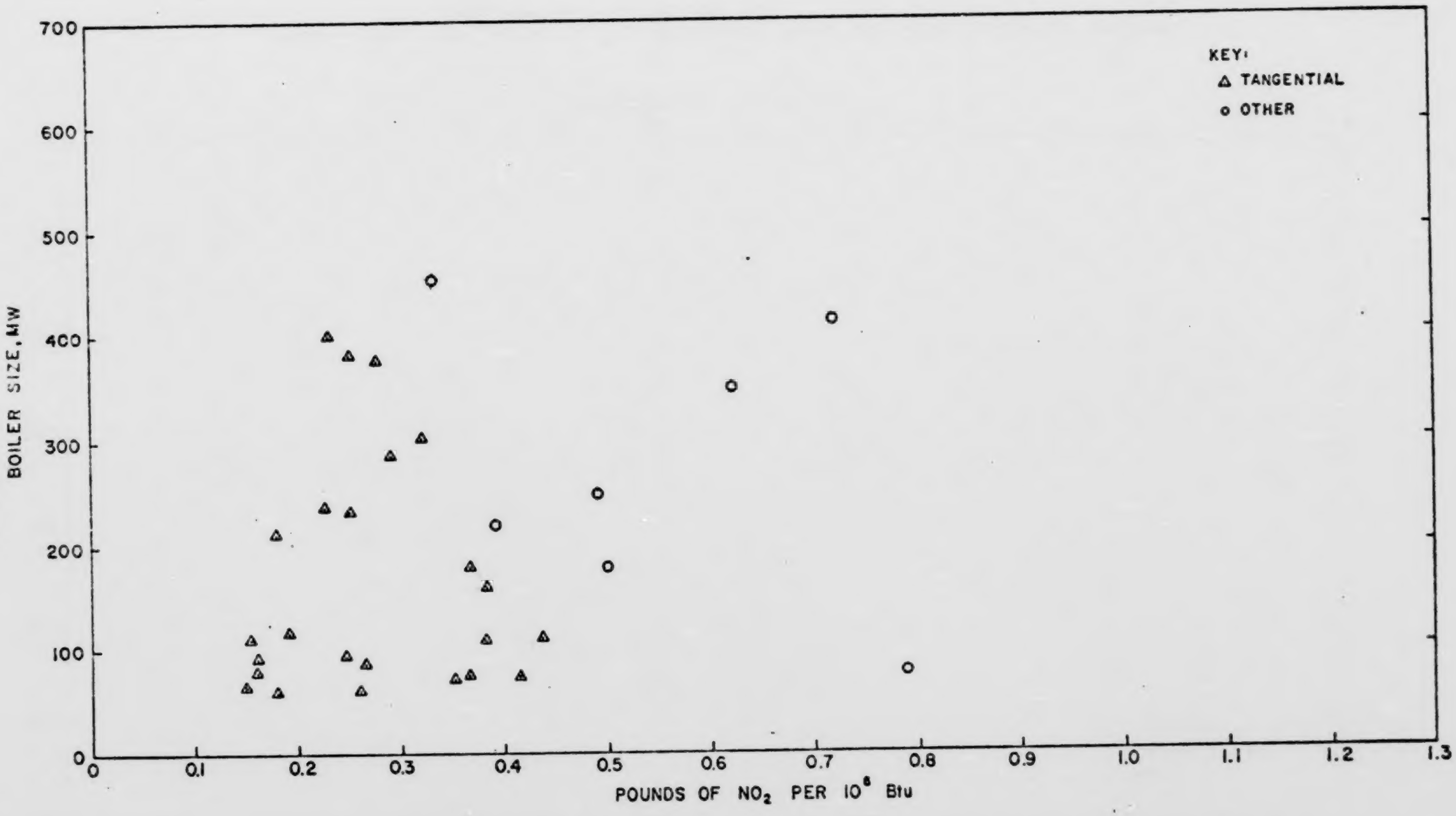

Figure 14. Test data of NO_x emissions from oil-fired utility boilers (from references 61 and 80)

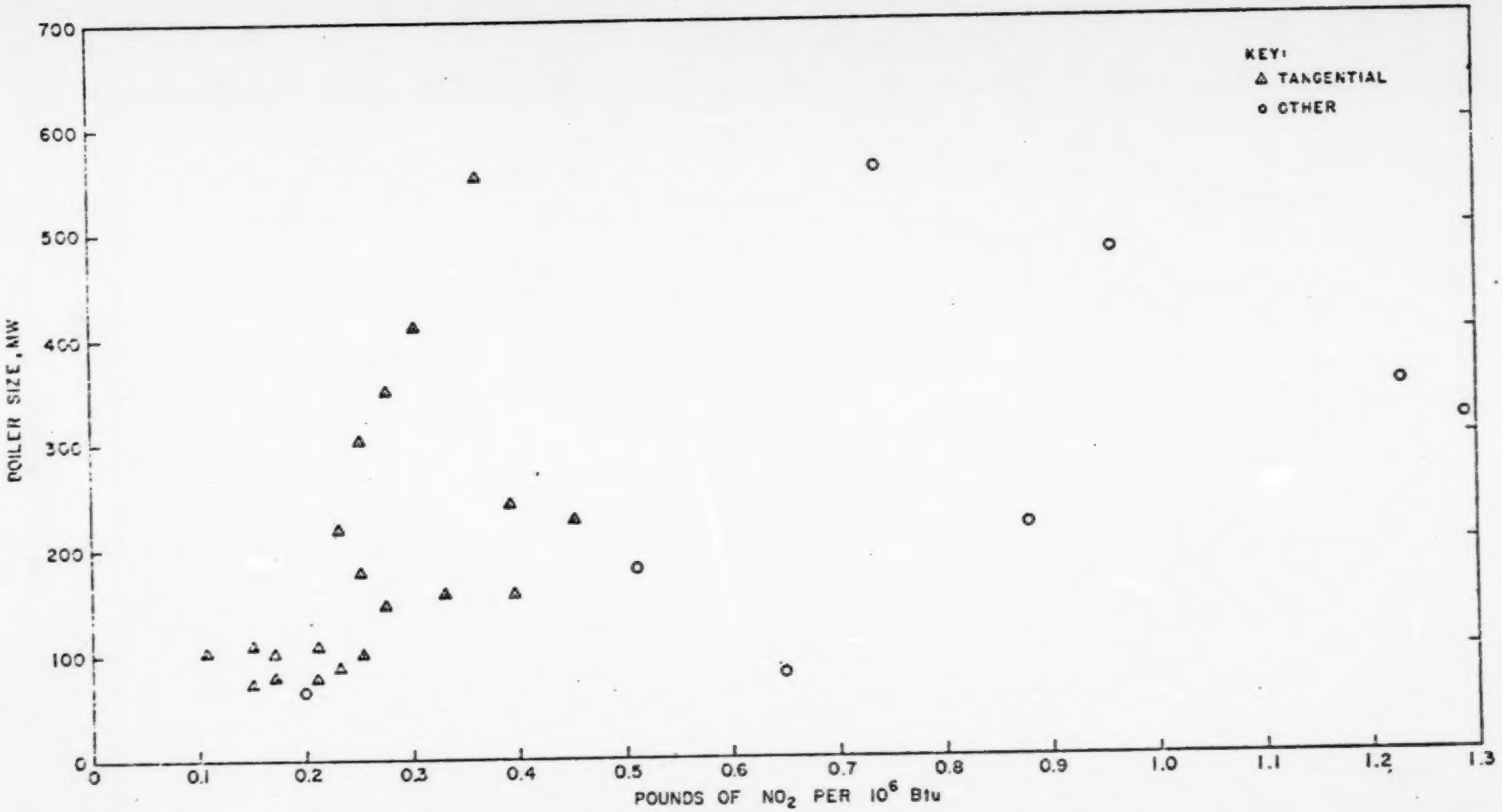

Figure 15. Test data of NO_x emissions from gas-fired utility boilers (from references 61 and 80)

can be used to calculate emission factors in terms of pounds of NO_2 emitted per million cubic feet of gas burned. These emission factors compare with the EPA emission factors as follows:

	Emission factor (lb $NO_2/10^6$ ft^3)	
Firing type	Figure 15	EPA[9]
Tangential	280	300
Other than tangential	830	700

For the tangentially-fired units the difference between emission factors is 7 percent. For the other units the difference is 19 percent. The EPA emission factors were used to estimate the stack emission.

Hydrocarbons - Stationary combustion is a relatively minor source of hydrocarbons, contributing approximately 1 percent to the total nationwide emissions in 1974. Electric power generation contributed 0.3 percent to the total. These emissions of hydrocarbons result from the incomplete combustion of carbonaceous fuels. Hydrocarbons may be emitted from combustion units because of the poor mixing of the combustion gases producing localized fuel rich areas in which there will be insufficient oxygen for complete combustion.

Hydrocarbons are often measured as part of NO_x control programs. Crawford et al.,[73] in a recent study, measured hydrocarbon emissions at 12 pulverized coal-fired boilers during 240 test runs and found that the concentrations were generally below the limit of the measuring equipment (i.e., less than 1 ppm). Crawford's data suggest an emission factor of less than 0.02 lb/ton. Even when low NO_x combustion methods were being tested hydrocarbon emissions were near 0.02 lb/ton. The emission factors used for Table 27 are the EPA emission factors;[9] i.e., 1 lb/ton for coal burning systems employing spreader stokers and 0.3 lb/ton for all other boilers.[9] The emission factor of 0.3 lb/ton was derived from data presented by Cuffe et al.[81] Emission factors for oil- and gas-fired boilers are 2 lb/10^3 gallons and 1 lb/10^6 ft^3, respectively.

Carbon Monoxide - Stationary combustion is a relatively minor source of carbon monoxide, contributing approximately 1 percent to the total nationwide emissions in 1974. Electric power generation contributed 0.2 percent to the total. CO is formed as an intermediate product of reactions between carbonaceous fuels and oxygen. When less than the theoretical amount of oxygen required for complete combustion is supplied, CO is a final product of the reaction. CO may also be found from the dissociation of CO_2 at high temperatures.[82]

$$CO_2 \rightleftarrows CO + O$$

The thermodyanmic equilibrium favors the dissociation of CO_2 at high temperatures. Thus, increasing the temperature increases the equilibrium concentration of CO. Rapid quenching of the combustion products then "freezes" the concentration of CO.

For minimum CO emissions, combustion equipment is designed for rapid reaction rates and long reaction times. Rapid reaction rates are promoted by: providing intimate contact between fuel and air; furnishing sufficient but not excessive air for complete combustion; increasing the combustion temperature by preheating the fuel and air; and minimizing the heat loss during combustion of the fuel. After complete combustion, slow cooling of the gases promotes complete oxidation of CO to CO_2.

Control of CO emissions is attained by proper adjustment of the air-fuel ratio. Insufficient air for complete combustion will produce high concentrations of CO. Excess air which lowers the combustion temperature below the optimum will also increase the concentration of CO. Insufficient mixing of the gases in the combustion units will produce localized fuel rich areas which promote the formation of CO.

Carbon monoxide is often measured as part of NO_x control programs. One such study involved 12 pulverized coal-fired boilers in the range 105 to 800 MW.[73] The reported CO emissions had a mean of 1.6 ± 0.6 lb/ton at a 95 percent confidence level. The emission factors used for Table 27 are the EPA emission factors (AP-42).[9] For utility boilers the emission factor is 1 pound of CO per ton of coal burned except for stoker-fired boilers for which the emission factor is 2 lb/ton. Emission factors for oil- and gas-fired utility boilers are 3 lb/ton 1000 gallons and 17 lb/10^6 ft^3, respectively.

Polycyclic Organic Matter (POM) - Emissions of organic materials from utility boilers are presented in Table 27 for benzene soluble organic matter (BSO), particulate polycyclic organic matter (PPOM), and benzo(a) pyrene (BaP). These estimates are based on data given in references 37, 74, and 83. Emissions of POM are largely due to incomplete combustion and as a result the combustion efficient utility boilers are only minor sources of POM.[84] The importance of combustion efficiency is illustrated in Figure 16 where BaP emission rates are plotted against gross heat input for various combustion units. The lowest emissions are representative of utility boilers; the highest emission rate sources are representative of residential heating units.

Most source estimates of POM are for BaP rather than PPOM and in addition the limited amount of data on POM and PPOM are not easily compared. Many compounds comprising POM are volatile[85] at typical stack temperatures but condense at ambient temperatures onto fly ash particles after leaving the stack. Thus the differentiation between PPOM and total POM is dependent upon whether these emissions are sampled in stack or after emerging from the stack. No estimates have been found for total POM; however, Table 35, from a 1973 Mitre report,[86] lists total annual POM emissions from coal, oil and gas utility plants. It is interesting to note that in the case of coal-fired boilers the Mitre estimates are similar to those given in Table 27 for BSO estimates.

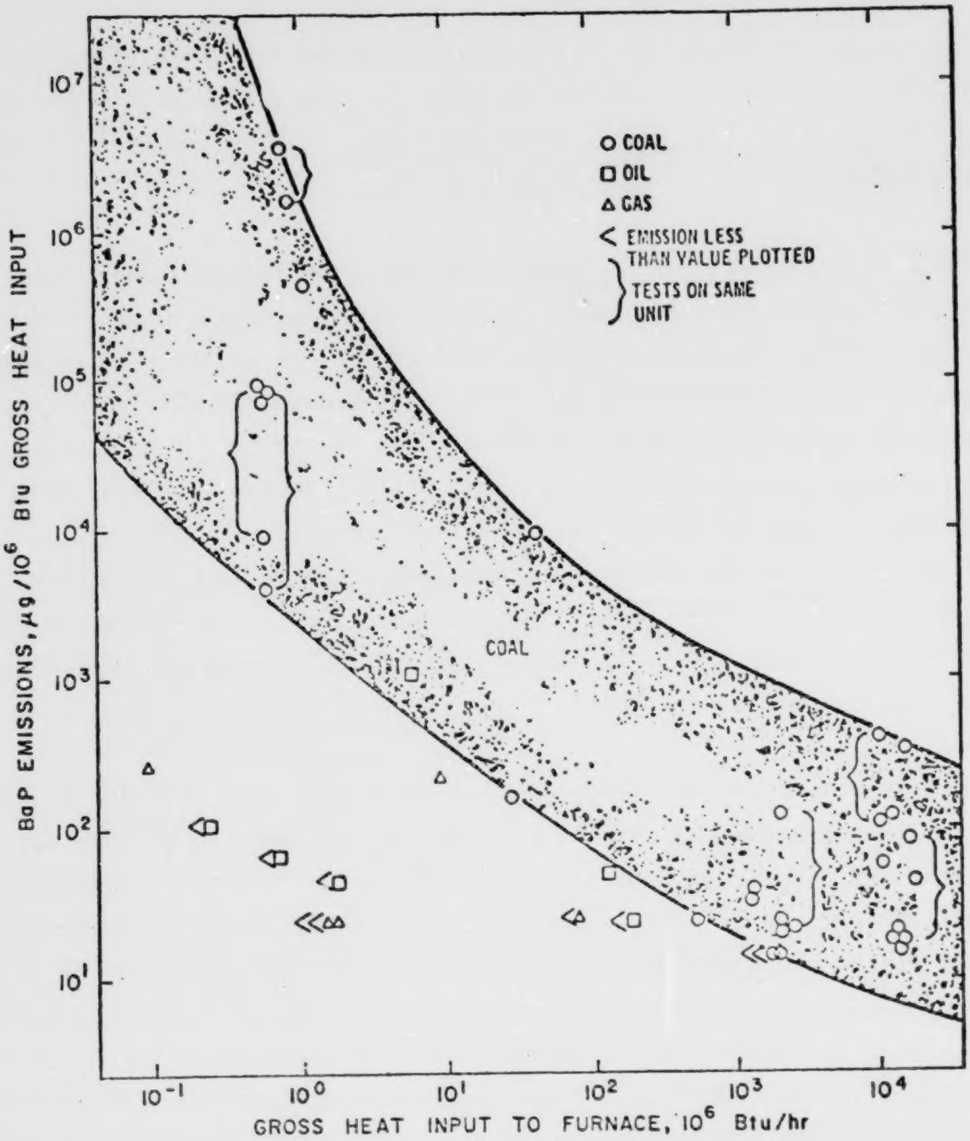

Figure 16. Benzo(a)pyrene emissions from coal, oil, and natural gas heat-generation processes[83]

Table 35. TOTAL POM EMISSIONS, MITRE ESTIMATE[86]

Power plant boilers	Annual emission in tons
Pulverized coal	8,980
Stoker coal	1,032
Cyclone coal	310
All oil	7,675
All gas	6,151

The data given in Table 36 are taken from references 74 and 83 and represent the PPOM found by summation of the emissions of the following 10 POM compounds:

- Pyrene
- Benzo(a)pyrene
- Benzo(e)pyrene
- Perylene
- Benzo(ghi)perylene
- Anthanthrene
- Coronene
- Anthracene
- Phenanthrene
- Fluoranthene

Using the mean value from the reported data and the heat input from coal used by steam-electric plants, the annual emissions of PPOM were calculated. Tangentially-fired boilers make up 50 percent of the capacity of coal-fired power plants, but only two values were reported for them. These two values have a mean of approximately 1,000 μg/10^6 Btu, which is higher than the mean value for all types.

Emissions of BaP from oil- and gas-fired sources were low in comparison to emissions from coal-fired sources, as shown in Figure 16. Detectable concentrations of BaP were found in only two of the six oil-fired units tested. Similarly BaP was detected in only two of the five gas-fired units tested. The estimates given in Table 27 are based on an estimated rate of 10 μg/10^6 Btu of total PPOM.

Table 36. SUMMARY OF AVAILABLE PPOM DATA

Boiler type	PPOM, $\mu g/10^6$ Btu	Reference
Vertically fired, dry bottom	419	83
Vertically fired, dry bottom	319	83
Vertically fired, dry bottom	736	83
Vertically fired, dry bottom	473	83
Frontwall fired, dry bottom	646	83
Frontwall fired, dry bottom	194	83
Tangential, dry bottom	1,019	83
Opposed, downward inclined, wet bottom	1,103	83
Opposed, downward inclined, wet bottom	454	83
Opposed, downward inclined, wet bottom	345	83
Vertical	374	74
Tangential	984	74
Frontwall	309	74
Horizontally opposed	1,326	74
Cyclone	1,943	74
Cyclone	3,354	83
Mean, all tests	885	
Standard deviation	787	
Btu input, coal power plants, 1974	8.5×10^{15}	
Total annual PPOM emissions from coal-fired power plants	9.5 tons	

Estimates of benzene soluble organics and BaP were calculated for coal using the data presented in reference 83. Values for oil and gas were obtained using the same ratios of PPOM/BaP and PPOM/benzene soluble organics obtained for coal.

Only one reference[181] reported data for emissions of polychlorinated biphenyls (PCB) from combustion. The average emission rate from a 125 MW pulverized coal-fired boiler was 0.8 mg/10^6 Btu. Assuming the same emission rate for all coal-fired boilers, the total PCB emissions from coal would be 7.5 tons per year. No data were found for emissions of other polyhalogenated hydrocarbons (PHH) from coal and no data were found for any PHH emissions from oil or gas.

Trace Elements - Much of the discussion that follows deals with trace element emissions from the combustion of coal. These emissions are much greater than those from oil or gas because the concentrations of most trace elements are greatest in coal. Trace elements present in appreciable amounts in petroleum are Ni, V, and Na. No trace elements are present in appreciable amounts in gaseous hydrocarbons.

The concentration levels of such toxic trace elements as Sb, As, Be, Cd, F, Pb, Hg, Se, Tl, and V have been shown to be two to three orders of magnitude greater in urban aerosols (0.1 to 10 μm) than in the earth's crust.[38,87] Particulates from coal combustion have been examined as a major source of these elements;[88] however, it has been found that the concentrations of most trace elements on fly ash particles produced by coal combustion are one to two orders of magnitude less than in the urban aerosols. Nevertheless, because the trace elements are concentrated largely on the surfaces of fly ash particles from which they may be readily desorbed following inhalation, trace element emissions from coal combustion pose a possible health hazard.

Almost every naturally-occurring element has been detected in coal.[40,89] References to minor and trace elements in coal are listed in Table 37. Attempts to characterize the trace element content of coal and to determine the fate of trace elements following combustion have had limited success. The chemical composition of coal varies greatly from one deposit to another even in the same seam and it is therefore difficult to extract a representative sample for analysis.[39-42,90,91] The ash content is dependent upon the care taken in mining, especially when there are ore beds nearby, and the cleaning and coal preparation processes used.

Considerable attention has been given to the development of accurate and reliable methods for the analysis of coal but adequate methods have become available only recently. In a recent EPA-sponsored study[92] instrumental neutron activation analysis (INAA) was used in four laboratories to measure trace element concentrations in coal and fly ash samples prepared by the National Bureau of Standards (NBS). For most of the 37 elements measured in the coal and the 41 elements measured in the fly ash, agreement among the laboratories was good; and for the 12 elements for which NBS had assigned values agreement with the NBS values was good. The results of the 1974 study are shown in Tables 38 and 39.

Trace elements are transferred during combustion to particles which range in size from less than 0.1 μm to greater than 100 μm.[101] Particulate control devices remove most of the large particles and substantial amounts of the small particles from the combustion gases leaving the furnace, but because of variations in equipment design, emissions to the atmosphere from a given unit must be determined by stack gas sampling. Many trace elements are concentrated on the surfaces of particles with the highest concentrations found on the smallest particles. Groups at Oak Ridge National Laboratories,[93-95,100,102,103] the University of Colorado,[95,105] the University of Illinois at Urbana,[85,89,96,101,106] and the University of Maryland,[87,97,107] have studied the dependence of concentration on particle size in efforts to complete mass balances for power plant units.

Table 37. MINOR AND TRACE ELEMENTS IN COAL

Element	Symbol	References
Actinium	Ac	
Aluminum	Al	38, 40, 41, 93-96
Antimony	Sb	
Arsenic	As	38, 40, 41, 93-98
Astatine	At	
Barium	Ba	40, 42, 91, 93, 95
Beryllium	Be	38-42, 91, 96, 98
Bismuth	Bi	40, 96
Boron	B	39-42, 91
Bromine	Br	40, 41, 91, 93, 94, 97
Cadmium	Cd	38, 40-42, 91, 93, 94, 96, 98
Calcium	Ca	38, 40-41, 94, 96
Cerium	Ce	40, 91, 93, 94
Cesium	Cs	40, 91, 93, 94
Chlorine[a]	Cl	40, 91, 93, 94
Chromium	Cr	39-42, 91, 93, 94, 96, 98
Cobalt	Co	39-41, 91, 93, 94, 96
Copper	Cu	39-42, 91, 93-96, 98
Dysprosium	Dy	40
Erbium	Er	40
Europium	Eu	40, 91, 94
Fluorine	F	38, 40-42, 91
Francium	Fr	
Gadolinium	Gd	40
Gallium	Ga	39-41, 93, 94
Germanium	Ge	39-41
Hafnium	Hf	40, 93, 94
Holmium	Ho	40
Iodine	I	40, 97
Iron[a]	Fe	39-42, 91, 93-96

Table 37 (continued). MINOR AND TRACE ELEMENTS IN COAL

Element	Symbol	References
Lanthanum	La	39, 40, 91-94
Lead	Pb	38, 40-42, 93-98
Lithium	Li	40, 42, 91
Lutetium	Lu	40
Magnesium[a]	Mg	38, 40-42, 93, 94, 96
Manganese	Mn	40-42, 91, 94, 96, 98
Mercury	Hg	38, 40-42, 93-95, 97-99
Molybdenum	Mo	39-41, 91, 93-95
Neodymium	Nd	40
Nickel	Ni	39-42, 91, 93, 94, 98
Niobium	Nb	40, 95
Phosphorus	P	40, 41
Polonium	Po	95
Potassium[a]	K	38, 40-42, 91, 93, 94, 96
Praseodymium	Pr	40
Protactinium	Pa	
Radium	Ra	
Rubidium	Rb	40, 93-95
Samarium	Sm	40, 93, 94
Scandium	Sc	40, 91, 93, 94
Selenium	Se	38, 40-42, 91, 93-98, 100
Silicon	Si	38, 40-42, 93, 94, 96
Silver	Ag	40, 42, 91
Sodium[a]	Na	38, 40, 42, 91, 93, 94
Strontium	Sr	40, 42, 93-95
Tantalum	Ta	40, 91, 93, 94
Tellurium	Te	40
Terbium	Tb	40, 91
Thallium	Tl	40, 96
Thorium	Th	40, 93, 94
Thulium	Tm	40

Table 37 (continued). MINOR AND TRACE ELEMENTS IN COAL

Element	Symbol	References
Tin	Sn	39-42, 96
Titanium[a]	Ti	38-41, 93, 94, 96
Tungsten	W	40
Uranium	U	40, 93, 94
Vanadium	V	38, 40-42, 91, 93, 94, 96, 98
Ytterbium	Yb	40, 91
Yttrium	Y	39, 40, 95
Zinc	Zn	40-42, 91, 93-96, 98
Zirconium	Zr	40, 41, 95

[a] Minor elements: about 1 percent or more, on ash basis.

The process by which trace elements are enriched on the smallest particles seems to begin in the combustion zone with the volatilization of some chemical species containing the element. Beyond the combustion zone, condensation and adsorption on particulate surfaces takes place. Because the rate of adsorption is dependent linearly on surface area, the highest concentrations occur on those particles with the greatest ratio of surface area to volume; i.e., the smallest particles.

Trace elements can be classified by their degree of enrichment in fly ash. The disposition of minor and trace elements during combustion and a qualitative estimate of the degree of their enrichment in fly ash are presented in Table 40. Elements listed in Table 40, which are enriched in fly ash or volatilized, are generally found in coal in the form of sulfides which are more volatile than silicates which are generally the forms of the elements not enriched.

Table 38. ELEMENTAL CONCENTRATIONS IN NBS COAL (SRM1632)[92] (μg/g UNLESS % INDICATED)

Element	Maryland		Battelle concentration (6 determinations unless noted)	Livermore concentration, 5 determinations each	Washington state		Average	
	Concentration	No. of determinations			Concentration	No. of determinations	Concentration	No. of values
Na	399 ± 20	9	420 ± 30[a]	313 ± 22	424 ± 20	5	414 ± 20	3
Mg (%)	0.16 ± 0.02	5	0.21 ± 0.07				0.20 ± 0.05	2
Al (%)	1.79 ± 0.18	6	1.73 ± 0.08	2.0 ± 0.1			1.85 ± 0.13	3
Cl	970 ± 140	12	840 ± 200	760 ± 60	1020 ± 90	5	890 ± 125	4
K (%)	0.27 ± 0.01	5	0.23 ± 0.01 0.284 ± 0.008[b]	0.226 ± 0.008	0.33 ± 0.10	5	0.28 ± 0.08	5
Ca (%)	0.41 ± 0.05 0.47 ± 0.06[c]	2 3		0.42 ± 0.07			0.43 ± 0.05	3
Sc	3.7 ± 0.15	6	3.4 ± 0.3	3.9 ± 0.2	3.9 ± 0.4	21	3.7 ± 0.3	4
Ti	960 ± 160 830 ± 200[c]	3 3	1100 ± 200	1100 ± 100	1140 ± 60	4	1040 ± 110	5
V	37 ± 3	5	33 ± 4	38 ± 3	37.7 ± 1.2	4	36 ± 3	4
Cr	19.7 ± 0.8	5	19 ± 2	19 ± 1	21 ± 2	16	19.7 ± 0.9	4
Mn	41 ± 2	6	41 ± 6	43 ± 3			43 ± 4	3
Fe (%)	0.86 ± 0.06	6	0.81 ± 0.07	0.82 ± 0.04	0.87 ± 0.07	21	0.84 ± 0.04	4
Co	5.6 ± 0.2	6	5.2 ± 0.4	6.0 ± 0.3	5.9 ± 0.4	21	5.7 ± 0.4	4
Ni			16 ± 4		20 ± 4	10	18 ± 4	2
Zn	30 ± 10	4					30 ± 10	1
As	5.7 ± 0.2 8 ± 2[c]	7 3	5.7 ± 0.5	5.0 ± 0.7	8.0 ± 0.4	5	6.5 ± 1.4	5
Se	3.1 ± 0.3	5	3.3 ± 0.4	3.5 ± 0.4	3.7 ± 0.4	11	3.4 ± 0.2	4
Br	20 ± 4	5	17 ± 2	19 ± 2	21.4 ± 0.7	5	19.3 ± 1.9	4
Rb	20 ± 2[c]	3	19 ± 2		23 ± 2	11	21 ± 2	3
Sr			170 ± 20		152 ± 21	21	161 ± 16	2
Ag			0.06 ± 0.03				0.06 ± 0.03	1
In				0.20 ± 0.12			0.20 ± 0.12	1
Sb	4.3 ± 3.0	6	3.7 ± 2.0	4.1 ± 5.3	3.3 ± 1.1	15	3.9 ± 1.3	4
Cs	1.4 ± 0.1	5	1.4 ± 0.1		1.49 ± 0.12	11	1.4 ± 0.1	3
Ba	330 ± 20	6	390 ± 20	327 ± 19	360 ± 35	14	352 ± 30	4
La	11.3 ± 0.5	5	10.5 ± 0.5	9.1 ± 0.6	11.9 ± 0.5	5	10.7 ± 1.2	4
Ce	20.4 ± 0.8	6		18.5 ± 0.7			19.5 ± 1	2
Sm	1.83 ± 0.07	13	1.7 ± 0.3	1.48 ± 0.07			1.7 ± 0.2	3
Eu	0.33 ± 0.03	6	0.28 ± 0.01	0.32 ± 0.01	0.33 ± 0.04	10	0.33 ± 0.04	4
Tb	0.22 ± 0.05	5	0.23 ± 0.06				0.23 ± 0.05	2
Yb	0.7 ± 0.1	5					0.7 ± 0.1	1
Lu	0.14 ± 0.01	6					0.14 ± 0.01	1
Hf	0.95 ± 0.05	5	0.97 ± 0.1	0.72 ± 0.06	0.72 ± 0.10	21	0.96 ± 0.05	3
Ta	0.21 ± 0.02	7	0.23 ± 0.05		0.29 ± 0.05	21	0.24 ± 0.04	3
W	0.87 ± 0.10	5		0.6 ± 0.3			0.75 ± 0.17	2
Th	3.0 ± 0.2	6	3.4 ± 0.6 3.45 ± 0.10[b,d]	3.0 ± 0.2	3.1 ± 0.2	16	3.2 ± 0.2	5
U			1.41 ± 0.07[b,d]				1.41 ± 0.07	1

[a] Twelve determinations.

[b] Determined by direct γ-ray counting of natural radioactivity.

[c] Determined by instrumental photon activation analysis.

[d] One sample of 100 g was counted five times for 1000 min each.

Table 39. ELEMENTAL CONCENTRATIONS IN NBS FLY ASH (SRM1633)[92]
(μg/g UNLESS % INDICATED)

Element	Maryland		Battelle concentration (6 determinations unless noted)	Livermore concentration, 5 determinations each	Washington state		Average	
	Concentration	No. of determinations			Concentration	No. of determinations	Concentration	No. of values
Na	3400 ± 200	9	3700 ± 200	2800 ± 200	2970 ± 50	4	3200 ± 400	4
Mg (%)	1.50 ± 0.16	6	2.08 ± 0.41				1.8 ± 0.4	2
Al (%)	13.2 ± 0.5	5	12.6 ± 0.4	12.1 ± 0.6			12.7 ± 0.5	3
Si (%)	21 ± 2[a]	3					21 ± 2	1
Cl	42 ± 10	4					42 ± 10	1
K (%)	1.40 ± 0.08	5	1.71 ± 0.03[b]	1.6 ± 0.1	1.73 ± 0.08	4	1.61 ± 0.15	4
Ca (%)	4.2 ± 0.4	3		4.5 ± 0.3			4.7 ± 0.6	3
	5.3 ± 0.5[a]	3						
Sc	27 ± 1	7	27 ± 1	28 ± 2	26.2 ± 1.7	20	27 ± 1	4
Ti	7300 ± 400	3	7600 ± 800	7200 ± 700	7550 ± 250	4	7400 ± 300	5
	7300 ± 310[a]	3						
V	231 ± 25	6	220 ± 15	244 ± 24	244 ± 12	5	235 ± 15	4
Cr	130 ± 6	7	131 ± 8	126 ± 10	122 ± 7	20	127 ± 6	4
Mn	509 ± 20	8	489 ± 11	506 ± 23	480 ± 12	5	496 ± 19	4
Fe (%)	6.2 ± 0.3	7	6.5 ± 0.3	5.8 ± 0.3	6.2 ± 0.5	19	6.2 ± 0.3	4
Co	41.2 ± 1.6	6	40 ± 2	42 ± 2	42.8 ± 2.1	14	41.5 ± 1.2	4
Ni	92 ± 6[a]	2			105 ± 13	10	98 ± 9	2
Zn	216 ± 25[a]	3					216 ± 25	1
As	60 ± 2.5	9	61 ± 5	52 ± 3	56 ± 3	4	58 ± 4	5
	61.5 ± 3.0[a]	5						
Se	10.3 ± 1.4	5	8.8 ± 1.2	11.5 ± 1.4			10.2 ± 1.4	3
Br			12 ± 4				12 ± 4	1
Rb	126 ± 10[a]	2	124 ± 10		126 ± 9	15	125 ± 10	3
Sr			1900 ± 200		1500 ± 200	20	1700 ± 300	2
Y	62 ± 10[a]	3					62 ± 10	1
Zr	301 ± 20[a]	2					301 ± 20	1
In				0.32 ± 0.10			0.32 ± 0.10	1
Sb	7.8 ± 0.7	9	7.2 ± 0.8	6.4 ± 0.4	6.3 ± 0.4	10	6.9 ± 0.6	5
	7.0 ± 1.1[a]	3						
I	2.9 ± 1.2[a]						2.9 ± 1.2	1
Cs	7.9 ± 0.9	5	9.9 ± 0.8		8.0 ± 0.8	11	8.6 ± 1.1	3
Ba	2700 ± 200	7	3400 ± 400	2600 ± 200	2700 ± 50	20	2700 ± 200	4
La	82 ± 3	6	82 ± 4[c]	65 ± 7	82 ± 2	4	82 ± 2	3
Ce	136 ± 12	8		135 ± 7			146 ± 15	2
Sm	13.6 ± 0.6	8	12.4 ± 0.5[c]	11.1 ± 0.7			12.4 ± 0.9	3
Eu	2.9 ± 0.2	7	2.3 ± 0.1	2.2 ± 0.2	2.7 ± 0.2	15	2.5 ± 0.4	4
Tb	1.7 ± 0.25	5	2.0 ± 0.3				1.9 ± 0.3	2
Yb	5.1 ± 0.8	5	8.9 ± 0.9				7 ± 3	2
Lu	1.0 ± 0.1	8					1.0 ± 0.1	1
Hf	7.9 ± 0.4	7	8.2 ± 0.8	8.2 ± 0.8	7.5 ± 0.5	19	7.9 ± 0.4	3
Ta	1.64 ± 0.13	6	1.7 ± 0.3		2.1 ± 0.3	18	1.8 ± 0.3	3
W	5.7 ± 1.0	5		3.5 ± 1.1			4.6 ± 1.6	2
Pb	75 ± 5[a]	2					75 ± 5	1
Th	23.5 ± 1.0	6	28 ± 2	23 ± 1	23.2 ± 1.6	19	24.8 ± 2.2	5
			26.2 ± 1.1[b,d]					
U			12.0 ± 0.5[b,d]				12.0 ± 0.5	1

[a] Done by instrumental photon activation analysis.

[b] Done by direct γ-ray counting of natural radioactivity.

[c] Twelve determinations.

[d] One sample of 100 g counted five times for 1000 min each.

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Table 40. DISPOSITION OF MINOR AND TRACE ELEMENTS DURING COMBUSTION

Minor and trace elements not enriched in fly ash

Element	Symbol	References
Aluminum	Al	94-96, 103, 104
Barium	Ba	94, 103, 104
Beryllium	Be	103, 104
Bismuth	Bi	103
Calcium	Ca	94, 96, 104
Cerium	Ce	94, 103
Cobalt	Co	94, 96, 103
Europium	Eu	94
Hafnium	Hf	94, 103
Iron	Fe	94-96, 103, 104
Lanthanum	La	94, 103
Magnesium	Mg	94, 96, 103, 104
Niobium	Nb	95
Potassium	K	94, 96, 103
Rubidium	Rb	94, 95, 103
Samarium	Sm	94, 103
Scandium	Sc	94, 103
Silicon	Si	94, 96, 103
Strontium	Sr	94, 95, 103
Tantalum	Ta	94, 103
Thorium	Th	94, 103
Tin	Sn	103
Titanium	Ti	94, 96, 103, 104
Yttrium	Y	95

Table 40 (continued). DISPOSITION OF MINOR AND TRACE ELEMENTS DURING COMBUSTION

Minor and trace elements enriched in fly ash

Element	Symbol	References
Antimony	Sb	94-97, 103, 104
Arsenic	As	94-98, 103
Cadmium	Cd	38, 94, 96, 103, 104
Chromium	Cr	94, 96, 103, 104
Copper	Cu	94-96, 103, 104
Gallium	Ga	94, 103
Lead	Pb	94-98, 103, 104
Mercury	Hg	94, 95, 97-99, 103, 104
Nickel	Ni	94, 96, 103, 104
Polonium	Po	95
Selenium	Se	94-98, 100, 103, 104
Thallium	Tl	96
Zinc	Zn	94-96, 103, 104

Minor and trace elements partially volatilized during combustion

Element	Symbol	References
Arsenic	As	94-98, 103
Bromine	Br	94, 97, 103
Cadmium	Cd	38, 94, 96, 103
Chlorine	Cl	94, 103
Fluorine	F	42
Iodine	I	97
Lead	Pb	94-98, 103
Mercury	Hg	94, 95, 97-99, 103
Selenium	Se	94-98, 100, 103

A list of trace elements was made that included those known to be potentially hazardous or of interest to EPA. Mass balances reported by groups at the University of Colorado,[95,105] the University of Maryland,[87,97,107] Midwest Research Institute,[24] Oak Ridge National Laboratories[93,94,103] and Radian[104] were used to calculate for each trace element the fraction emitted to the atmosphere. These data are presented in Table 41. Differences in stack emissions are due to differences in coal properties and furnace design, as well as difficulties in analytical procedures. Because of the uncertainties in the data only one parameter was developed for each element and this parameter, derived from pulverized coal studies, was applied to all categories of coal combustion.

Battelle[108] has estimated that the radioactivity emitted by a 175 MW coal-fired boiler is in the range of 19-54 millicuries/year or 0.1-0.3 millicuries/MW. An earlier estimate[24] indicated a maximum of 200 millicuries/year for a similar sized plant or 1.1 millicuries/MW. Radioactive emissions will vary widely from plant to plant depending on the coal source. Lignites have a higher uranium content (about 80 ppm) than bituminous coals (about 10 ppm).[38] The quantity of radioisotopes emitted will also depend on the types present, the effect of furnace operating parameters and the effects of control equipment.

More important than the total quantity of radioactivity emitted by coal-fired power plants, which appears to be relatively small, is the type of isotopes emitted and their physical states. Similar to trace elements all naturally occurring radioisotopes are probably present in coal. Kaakinen[95,179] has measured radium 226, polonium 210 and lead 210 in coal, bottom ash and fly ash at a coal-fired power plant. Lead 210 and polonium 210 were concentrated in the fly ash.[95] It is suspected that volatile radioisotopes such as lead 210, polonium 210, bismuth 210 and radium daughter products are concentrated either in the flue gas or fine particulates. Because fine particulates are controlled less effectively than the larger particles and because fine particulates deposit in the

Table 41. TRACE ELEMENT STACK EMISSIONS FROM COAL-FIRED POWER PLANTS (%)[a]

Element	Valmont[b]	Chalk point[c]	Widows creek[d]		Allen[e]		Station I[f]	Station II[g]	Station III[h]	GCA estimate[i]
	A	A	A	B	A	B	B	B	B	
Sb	14	32	88		0	27	1.1	3.6	69	25
As	14	33			8	3.4	9.1	0.90	21	25
Ba		6	40	26	0	0.31	1.1	<0.1	<2.3	15
Be			44	26			0.52	<2.9	7.1	25
Bi										25
B							4.8	5.9	62	25
Br		98				100				100
Cd			82		0	2.3	15	3.2	50	35
Cl			95			97		100	100	100
Cr		10	35	39	0	1.2	13	13	47	25
Co		11	58	11	0	0.64	0.22	2.0	56	10
Cu	19		43	30			9.8	0.8	28	25
F			97				2.1	8.3	96	100
Fe	4.6		0	20	0	0.70	0.79	0.90	18	10
Pb	28	34	66	43	13	2.5	4.2	5.2	62	35
Mn		0	19	25	0	0.81	0.45	1.5	13	25
Hg	89	84	60			56	59		100	90
Mo	27						33	9.4	100	25
Ni		17	40	35			4.0	2.8		25
Se	80	52	12		45	12	2.7	15	83	70
Te			87	4.6						25
Tl										25
Sn			84	4.7						25
Ti		17	26	32	2	0.71	0.25	0.75	9.4	25
U					0	0.67	1.5	0.70	14	25
V		25	44	29	0	1.4	2.9	2.5	28	30
Zn	24	23	69	30	22	2.3	3.7	4.2	66	25
Zr	3.3	17								10

[a] Values in the table represent fractions in coal, expressed as %, released to the atmosphere. Values in column A were calculated from analyses of ashes collected from the unit; values in column B were calculated from analyses of fly ash and flue gas sampled from the stack.

[b] These data were obtained in a University of Colorado study[95,106] from a 180 MW pulverized coal-fired unit. The unit was fitted with an economizer, a mechanical dust collector, and both an electrostatic precipitator and a wet scrubber which had been installed in parallel.

[c] These data were obtained in a University of Maryland study[87,97,109] from a 355 MW wet bottom pulverized coal-fired unit. The unit was fitted with an economizer and an electrostatic precipitator. The study was not designed particularly to produce a mass balance.

[d] These data were obtained in a Midwest Research Institute study[24] from a 125 MW dry bottom pulverized coal-fired unit fitted with an economizer and a mechanical dust collector. The unit was not fitted with an electrostatic precipitator.

[e] These data were obtained in an Oak Ridge National Laboratories study[93,94,102-104] of a 290 MW crushed coal-fired cyclone unit fitted with an economizer and a high efficiency electrostatic precipitator.

[f] These data were obtained in a Radian study[104] from a 330 MW pulverized subbituminous coal-fired unit fitted with high efficiency venturi scrubbers.

[g] These data were obtained in a Radian study[104] from a 350 MW pulverized subbituminous coal-fired unit fitted with a high efficiency electrostatic precipitator.

[h] These data were obtained in a Radian study[104] from a 250 MW crushed lignite-fired cyclone unit fitted with a mechanical dust collector.

[i] These estimates of trace element emissions apply strictly to pulverized coal-fired units only. They were made after examining the mass balances from the Valmont, Chalk Point, Widows Creek station I and station II units, all of which burn pulverized coal, and other trace element studies not involving mass balances[85,89,96,101,106] In addition they are based on national average contact device characteristics.

lungs, radioisotopes may be a problem even though the amounts emitted are not large. The National Atmospheric Research Center plans to measure radioisotope emission as a function of particle size.[180]

Total radioactive emissions from coal based on 1 millicurie per megawatt capacity are estimated to be 200,000 millicuries/year. Emissions of lead 210, polonium 210 and radium 226 are estimated to be 30,000, 30,000 and 600 millicuries/year.

Internal Combustion

The generation of electricity by utilities via internal combustion accounts for 0.08 percent of total particulates, 0.02 percent of sulfur oxides, 2.2 percent of nitrogen oxides, 0.04 percent of hydrocarbons, and 0.03 percent of carbon monoxide emissions from all man-made sources. It accounts for 0.4 percent of total particulates, 0.03 percent of sulfur oxides, 4.9 percent of nitrogen oxides, 9.9 percent of hydrocarbons, and 3.8 percent of carbon monoxide emissions from stationary combustion sources.

The major pollutant from gas turbines is nitrogen oxides. The nitrogen oxides are formed in the high temperature region of the combustor. Regenerative cycles increase the combustor temperature thus increasing the amount of nitrogen oxides produced.

The major pollutant from reciprocating engines is nitrogen oxide, although significant amounts of carbon monoxide and unburned hydrocarbons are also produced. Diesel engines produce greater quantities of pollutants than spark engines. Total nationwide emission estimates of particulates (including <3 micron diameter particulates), sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, polycyclic organic matter, and trace elements are presented in Table 42. The estimates are based on the EPA-NEDS emission factors[9] listed in Table 43 and on the methods described in the notes following Table 42.

Table 42. EMISSIONS FROM THE GENERATION OF ELECTRICITY BY INTERNAL COMBUSTION[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[d] tons/yr		
		Total	$<3\mu$[c]	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
1.0.00.0.0	Electric Generation	4,500	1,600	16,000	7,100	120	360	11,000	11	0.8
1.2.00.0.0	Internal Combustion[b]	28		7.1	540	35	41			
1.2.20.0.0	Petroleum	26		6.5	370	30	25			
1.2.30.0.0	Gas	1.9		0.60	170	4.7	16			
1.3.00.0.0	Internal Combustion/ Gas Turbine	6.7		4.2	120	10	29			
1.3.20.0.0	Petroleum	5.1		3.6	69	5.7	16			
1.3.21.0.0	Residual Oil	0		0	0	0	0	0	0	0
1.3.22.0.0	Distillate Oil	5.1		3.6	69	5.7	16			
1.3.30.0.0	Gas	1.6		0.58	46	4.7	13			
1.4.00.0.0	Internal Combustion/ Reciprocating Engine	21		2.9	420	24	66			
1.4.20.0.0	Petroleum	21		2.9	300	24	63			
1.4.22.0.0	Distillate Oil	21		2.9	300	24	63			
1.4.30.0.0	Gas	0.33		0.014	120	0.028	2.7			

Table 42 (continued). EMISSIONS FROM THE GENERATION OF ELECTRICITY BY INTERNAL COMBUSTION[a]

		Trace elements,[e] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
1.0.00.0.0	Electric Generation	51	3,000	2,700	230	98	5,000	5,600	200	590,000	1,500
1.2.00.0.0	Internal Combustion[b]		0.065					0.086			
1.2.20.0.0	Petroleum		0.065					0.086			
1.2.30.0.0	Gas										
1.3.00.0.0	Internal Combustion/ Gas Turbine		0.06					0.08			
1.3.20.0.0	Petroleum		0.06					0.08			
1.3.21.0.0	Residual Oil	0	0	0	0	0	0	0	0	0	0
1.3.22.0.0	Distillate Oil	ND	0.06	ND				0.08	ND		ND
1.3.30.0.0	Gas										
1.4.00.0.0	Internal Combustion/ Reciprocating Engine		0.005					0.006			
1.4.20.0.0	Petroleum	ND	0.005	ND				0.006	ND		ND
1.4.22.0.0	Distillate Oil	ND	0.005	ND				0.006	ND		ND
1.4.30.0.0	Gas										

Table 42 (continued). EMISSIONS FROM THE GENERATION OF ELECTRICITY BY INTERNAL COMBUSTION[a]

		Trace elements,[e] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
1.0.00.0.0	Electric Generation	320	2,000	31,000	131,000	1,200	4500	48	510	4,900	740
1.2.00.0.0	Internal Combustion[b]		0.043				0.13				
1.2.20.0.0	Petroleum		0.043				0.13				
1.2.30.0.0	Gas										
1.3.00.0.0	Internal Combustion/ Gas Turbine		0.04				0.12				
1.3.20.0.0	Petroleum		0.04				0.12				
1.3.21.0.0	Residual Oil	0	0	0	0	0	0	0	0	0	0
1.3.22.0.0	Distillate Oil		0.04				0.12	ND		ND	ND
1.3.30.0.0	Gas										
1.4.00.0.0	Internal Combustion/ Reciprocating Engine		0.003				0.01				
1.4.20.0.0	Petroleum		0.003				0.01	ND		ND	ND
1.4.22.0.0	Distillate Oil		0.003				0.01	ND		ND	ND
1.4.30.0.0	Gas										

Table 42 (continued). EMISSIONS FROM THE GENERATION OF ELECTRICITY BY INTERNAL COMBUSTION[a]

		Trace elements,[e] tons/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
1.0.00.0.0	Electric Generation	28	9.3	100	55,000	1,500	6,700	2,000	1800
1.2.00.0.0	Internal Combustion[b]			1.1					
1.2.20.0.0	Petroleum			1.1					
1.2.30.0.0	Gas								
1.3.00.0.0	Internal Combustion/ Gas Turbine			0.82					
1.3.20.0.0	Petroleum			0.82					
1.3.21.0.0	Residual Oil	0	0	0	0	0	0	0	0
1.3.22.0.0	Distillate Oil			0.82			ND	ND	
1.3.30.0.0	Gas								
1.4.00.0.0	Internal Combustion/ Reciprocating Engine			0.30					
1.4.20.0.0	Petroleum			0.30			ND	ND	
1.4.22.0.0	Distillate Oil			0.30			ND	ND	
1.4.30.0.0	Gas								

[a] Values in the table represent total estimated emissions to the atmosphere from conventional stationary combustion sources in the continental United States. An entry of "ND" signifies that a trace element has not been detected when measured and an entry left blank signifies that no information is available. The emission factors used for this table are given in Table 43.

[b] Capacities and fuel consumption were taken from reference 6. The emissions were calculated by multiplying the emission factor by the fuel consumption for each pollutant and each fuel.[6] The sulfur content for distillate oil of 0.225 percent was taken from reference 110.

[c] No information was available on emissions of <3 micron particles.

[d] No information was available on emissions of organics.

[e] The internal combustion emissions for the trace elements were calculated by multiplying the fuel consumption by the trace element content of each fuel. For distillate oil reference 46 reported concentrations for As, Br, Cu, Mn, and Sn and reported that Sb, Ba, Cd, Cr, Hg, Ni, Se, V, and Zn were not detectable. Hydrocarbon gases were assumed to be free of trace elements.

Table 43. EMISSION FACTORS FOR INTERNAL COMBUSTION EMISSION ESTIMATES, TABLE 42

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
1.0.00.0.0	Electric generation	NA	NA	NA	NA	NA
1.2.00.0.0	Internal combustion	NA	NA	NA	NA	NA
1.2.20.0.0	Petroleum[b]	NA	NA	NA	NA	NA
1.2.30.0.0	Gas[c]	NA	NA	NA	NA	NA
1.3.00.0.0	Internal combustion/ gas turbine	NA	NA	NA	NA	NA
1.3.20.0.0	Petroleum	5	144S	68	5.6	15.4
1.3.21.0.0	Residual oil	X	X	X	X	X
1.3.22.0.0	Distillate oil	5	144S	68	5.6	15.4
1.3.30.0.0	Gas	14	0.6	413	42	115
1.4.00.0.0	Internal combustion/ reciprocating engine	NA	NA	NA	NA	NA
1.4.20.0.0	Petroleum	33.5	144S	469	375	102
1.4.22.0.0	Distillate oil	33.5	144S	464	375	102
1.4.30.0.0	Gas	14	0.6	3000	42	115

[a] Abbreviations used in the table have the following meanings

S = Multiply by weight percent sulfur

X = Fuel consumed in this combustion system is small; emission is assumed to be negligible.

NA = Emissions for this combustion system were calculated as the total of emissions from the appropriate subsystems.

[b] The emission factors for oil give values in terms of pounds of pollutant per 1000 gallons of oil burned.[9]

[c] The emission factors for gas give values in terms of pounds of pollutant per 10^6 cubic feet of gas burned.[9]

To obtain state emission estimates for purposes of assigning priorities to the various combustion systems it will be necessary to prorate the nationwide values by multiplying by the ratio of the fuel consumption in a state (ton/year) to the fuel consumption nationwide (ton/year). Fuel consumption estimates by state are provided in Appendix B.

ASH HANDLING EMISSIONS

Steam electric utility plants produce ash as a waste product of combustion. The ash is transported to a disposal system by either wet (sluicing) or dry (pneumatic) conveyance. Most utility plants (approximately 80 percent)[23] dispose of ash in settling ponds or basins with a wastewater overflow. The characteristics of the waste water are related to the physical and chemical properties of the ash and to the volume and initial quality of the water used. The quantity of water discharged and the concentration and composition of suspended and dissolved solids in the wastewater stream will depend upon wastewater characteristics and plant equipment and practices. Air emissions will occur as a result of wind erosion of landfill and from the dry collection and transport of ash. Ground and surface water contamination can result from leaching of waste water from landfill and settling ponds.

Ash Generated

The total amount of ash generated by utility boilers is available from data on file with the FPC.[23] Their data, after extrapolation of 1972 fuel consumption and ash generation data, yield a value of approximately 49,000,000 tons in 1974. Our estimate of total ash collected, as presented in Table 44 after adjustment for fuel consumption and application of emission controls, is approximately 47,000,000 tons in 1974. This estimate is somewhat higher than values of 40,000,000 tons and 43,000,000 tons given in references 36 and 111 after adjustment for 1974 fuel consumption. Variations are due to differences in values assumed for control efficiencies, fuel consumption, and average ash content of the fuel. Total fly ash collected is estimated to be 34 million tons per year in 1974, with other estimates (for 1975) ranging from 32 to 36 million tons per year.[112,113]

The relative contribution of the bottom ash and fly ash to the total was calculated using NEDS boiler population data and the NEDS value for fly ash production by boiler type adjusted for the application of control. Bottom ash is about 27.5 percent of the total ash generated on the basis of such calculations. However, the 27.5 percent bottom ash estimate is appreciably lower than that given in reference 114. This reference indicates that bottom ash (including boiler slag) accounted for about 36 percent of the total ash produced by utilities in 1971. The data presented in reference 114 were based on an Edison Electric Institute survey of essentially all U.S. power plants. The difference between the two estimates may be partially due to the high particulate emission factor values used by NEDS for pulverized dry boilers.

Disposal Methods

Information concerning the prevalence of disposal methods was based on FPC data and reference 114. The FPC data were analyzed to obtain an estimate of ponding as a disposal option. Based on fuel consumption, 80 percent of coal-fired utilities indicate that ponding is used as a disposal option. (As yet no definitive information concerning the application of lined ponds has been found.) The extent of landfill operations was determined by difference. The values reported in acres per year represent that area (25 feet deep) which is needed to contain the dry ash (density 100 lb/ft^3). Actual pond area requirements will greatly exceed the number reported in Table 44.[115]

The commercial utilization of ash has increased in recent years with the marked increase, shown for 1971 in Table 45, due to an increase in the use

Table 44. ASH HANDLING EMISSIONS: ELECTRIC UTILITIES, 1974

		Bottom ash, 10^3 tons	Fly ash, 10^3 tons	Total, 10^3 tons	Ash utilization, tons	Ponding		Landfill		Water[a] discharge, 10^6 gal/yr	Air emissions, 10^3 tons/yr
						acre/yr	acre feet/yr	acre/yr	acre feet/yr		
1.0.00.0.0	Electric generation	12,925	34,125	47,050	7,500,000	692	17,300	37	876	310,000	20
1.1.00.0.0	External combustion	12,925	34,125	47,050	7,500,000	692	17,300	37	876	310,000	20
1.1.10.0.0	Coal	12,900	34,100	47,000	7,500,000	692	17,300	37	872	310,000	20
1.1.11.0.0	Bituminous	12,550	33,200	45,750	7,300,000	673	17,300	36	850	301,000	19.3
1.1.11.1.0	Pulverized dry	5,350	27,800	33,150	5,300,000	480	17,300	26	610	218,200	14
1.1.11.2.0	Pulverized wet	2,300	3,850	6,150	980,000	90	16,800	5	115	40,300	2.6
1.1.11.3.0	Cyclone	4,700	1,300	6,000	950,000	88	12,200	4	115	39,400	2.5
1.1.11.4.0	All stokers	200	250	450	70,000	7	2,260	1	9	3,100	0.2
1.1.12.0.0	Anthracite	50	100	150	24,000	2.2	2,200	0.2	2.7	985	0.06
1.1.12.1.0	Pulverized dry	15	35	50	8,000	0.7	165	0.05	0.9	314	0.02
1.1.12.2.0	Pulverized wet	0	0	0	0	0	55	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0	18	0	0	0	0
1.1.12.4.0	All stokers	35	65	100	16,000	1.5	0	0.15	1.8	671	0.037
1.1.13.0.0	Lignite	300	800	1,100	174,000	16	0	0.8	21	7,160	0.47
1.1.13.1.0	Pulverized dry	180	480	660	105,000	9.6	37	0.5	12	4,300	0.28
1.1.13.2.0	Pulverized wet	45	120	165	26,000	2.4	400	0.12	3.2	1,070	0.07
1.1.13.3.0	Cyclone	45	120	165	26,000	2.4	240	0.12	3.2	1,070	0.07
1.1.13.4.0	All stokers	30	80	110	17,000	1.6	60	0.18	2.3	720	0.05
1.1.20.0.0	Petroleum	25	25	50	Nil	0.9	60	Nil	Nil	400	Nil
1.1.21.0.0	Residual oil	25	25	50	Nil	0.9	40	Nil	Nil	400	Nil
1.1.21.0.1	Tangential firing	10	10	20	Nil	0.4	23	Nil	Nil	180	Nil
1.1.21.0.2	All other	15	15	30	Nil	0.5	23	Nil	Nil	220	Nil
1.1.22.0.0	Distillate oil	Nil	Nil	Nil	Nil	Nil	9	Nil	Nil	Nil	Nil
1.1.22.0.1	Tangential firing	Nil	Nil	Nil	Nil	Nil	14	Nil	Nil	Nil	Nil
1.1.22.0.2	All other	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
1.1.30.0.0	Gas	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
1.1.30.0.1	Tangential firing	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
1.1.30.0.2	All other	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil

[a] See Tables 47 and 48 for properties of discharge waters.

Table 45. COMPARATIVE ASH PRODUCTION AND UTILIZATION[114]

Category	1966[a]	1969[b]	1970	1971
Ash produced, tons:				
Fly ash	17,123,144	21,091,406	26,538,019	27,751,054
Bottom ash	8,065,683	7,648,567	9,890,951	10,058,967
Boiler slag	NA	2,921,226	2,801,475	4,970,786
Total	25,188,827	31,661,199	39,230,445	42,780,807
Ash utilized, tons:				
Fly ash	1,355,138	1,927,493	2,158,345	3,253,206
Bottom ash	1,695,531	1,959,900	1,842,952	1,612,026
Boiler slag	NA	964,578	1,094,362	3,738,488
Total	3,050,669	4,851,971	5,095,659	8,603,720
Ash utilized, percent:				
Fly ash	7.9	9.1	8.1	11.7
Bottom ash	21.0	25.6	18.6	16.0
Boiler slag	NA	33.0	39.1	75.2
Total	12.1	15.3	13.0	20.1

[a] First year that data were taken.

[b] 1967 and 1968 data omitted from tabulation.

NA - Not available.

of boiler slag as road aggregate.[114] It was assumed that the ratio of ash utilized to ash produced in 1974 was 16 percent. The ash utilized figures include ash sold and ash removed from the plant site at no expense. This ash can be utilized in the application areas listed in Table 46.[114]

Progress in fly ash utilization is more advanced than for other types of waste utilization because of the greater quantities of fly ash collected. However, utilization of fly ash has not been as successful in the United States as in European countries. In 1969 Britain utilized 42 percent of its total fly ash production, France 55 percent and the United States only 9 percent.[116] Extensive work is now being done in the United States to enhance the use of ash. A discussion of this work will not be given here; instead the reader is referred to references 116 through 125 for a more thorough treatment of this subject.

Properties of Discharge Waters

The quality and quantity of ash handling waste water produced by electric utilities have been discussed earlier and illustrated in Figure 3 and Table 44. Table 47 presents the chemical properties of ash pond discharge water as derived from reference 36. In addition to the data presented in Table 47, it is important to note that the addition of ash to water immediately results in reductions in the pH and dissolved oxygen values. Ash streams are usually combined in a common system, thus the elemental composition of the combined ash will be basically that of the parent coal minus the volatile components and particulates not collected by control devices.

The volume of ash pond discharge waters, estimated to be 290,000 x 10^6 gallons per year based on FPC data, is in good agreement with estimates calculated from average pond discharge volumes of 5,000,000 gallons per day per 1,000 MW given in reference 36. Total ash pond volume discharge calculated in this fashion, assuming 80 percent application of ponding, is 310,000 x 10^6 gallons per year in 1974.

Table 46. ASH COLLECTION AND UTILIZATION, 1971[114]

	Fly ash, tons	Bottom ash, tons	Boiler slag (if separated from bottom ash), tons
Ash utilized:			
Mixed with raw material before forming cement clinker	104,222	NA	91,975
Mixed with cement clinker or mixed with cement (pozzolan cement)	16,536	NA	NA
Partial replacement of cement in —			
Concrete products	177,166	35,377	76,563
Structural concrete	185,467	NA	NA
Dams and other massive concrete	71,411	NA	NA
Lightweight aggregate	178,895	13,942	NA
Fill material for roads, construction sites, etc.	363,385	533,682	2,628,885
Stabilizer for road bases, parking areas, etc.	36,939	7,880	49,564
Filler in asphalt mix	147,655	2,833	81,700
Miscellaneous	98,802	475,417	428,026
Total	1,380,478	1,069,131	3,356,713
Ash removed from plant site at no cost to utility but not covevered in categories listed under "ash utilized"	1,872,728	542,895	381,775
Total ash utilized	3,253,206	1,612,026	3,738,488
Ash removed to disposal areas at company expense	24,497,848	8,446,941	1,232,298
Total ash collected	27,751,054	10,058,967	4,970,786

NA — Not applicable

Table 47. PROPERTIES OF ASH POND DISCHARGE WATERS[36]

Water parameter	Range of concentration, mg/ℓ
Total solids	300-3500
Total dissolved solids	250-3300
Total suspended solids	25-100
Oil and grease[a]	0-15
Hardness	200-750
Alkalinity	30-400
SO_4	100-300
Al	0.2-5.3
Cr	0.1
Na	20-173
NH_3	0.1-2
NO_3	0.1-6.1
Cl	20-2000
Cu	0.1-0.3
Fe	0.02-2.9

[a] Proposed federal standards (30-day average) .

Values for total suspended solids were also estimated from FPC data. The average loading was 70 mg/ℓ, and is within the range reported in reference 36. Use of this value results in a total suspended solids emission from ash handling of about 80,000 tons per year. This value is somewhat higher than the Hittman[111] estimate of about 55,000 tons per year but makes no allowances for background solids. It is also slightly greater than an average loading of 60 mg/ℓ given in reference 36 which was based on a sampling of 66 percent of coal-fired utilities.

The variability of chemical composition data is large. Average values have been determined in some cases, again based on a sampling of 66 percent of coal-fired utilities.[36] This reference also provides an extensive listing of ash pond overflow pollutants for about 30 utility plants. Data for Fe and Cu emissions obtained by ERCO, in a study of ash pond pollutants from the utility industry,[126] are within the general range of values reported in Table 47. The determination of average values for other elements will involve a study of data on file under the National Pollution Discharge Elimination System. Trace element concentrations for ash pond liquor are shown in Table 48 and are representative of the solubility of some elements. The values, however, cannot be considered representative of all ash pond liquors.[127] See Tables 24 and 25 for additional data concerning ash pond discharge.

Table 48. TRACE ELEMENT CONCENTRATIONS IN ASH POND LIQUOR[127]

Element	Concentration, ppm
Lead	0.01
Antimony	0.015
Barium	0.07
Manganese	0.075
Mercury	< 0.001
Beryllium	0.002
Boron	0.5
Nickel	0.015
Cadmium	0.01
Selenium	0.035
Zinc	0.03
Arsenic	0.01

Leachates from Ponds and Landfill

Leachates from ponds and landfill present a potential hazard through contamination of surface and ground waters. The concentration of heavy metals, particularly arsenic and cadmium are consistently in excess (5 to 100 times) of natural abundance. The trace metal contents of some ash wastes are so high as to be more comparable with low grade ores than natural soil environments.[117] Tables 49 and 50 list concentrations of major elements in ash and selected trace elements in bottom and fly ash.* The actual amounts of metals or other leachates released into water will depend upon the chemical state and the properties and flow of the water with which the fly ash comes into contact.

Air Emissions From Landfill

No definitive data on air emissions resulting from the collection, transport and landfill storage of ash was found in the literature. However, wind erosion from landfills or ash storage piles can be a significant local problem, as was noted in a recent stack testing program of a pulverized coal boiler in Nucla, Colorado.[54]

Attempts have been made to estimate the amount of air emissions attributable to storage of ash by application of the wind erosion equation given in reference 128. However, a large number of assumptions have to be made. If the worst possible conditions are assumed erosion losses can be high, on the order of 10^6 tons/year. Evaluation of other mineral and agricultural handling and storage emission factors indicate that, on the average, overall emission factors without control are generally in the range of 30 to 100 lb/ton. Application of the higher factor to ash storage also would result in high emissions ($\sim 2 \times 10^6$ tons/year) assuming 100 percent dry handling of the ash.

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*A more detailed listing of trace elements in ash can be found in Appendix C. This listing in conjunction with data from Tables 44 and 49 can be used to estimate the pollution potential of ash solid waste on a national basis. Coal consumption values by State (Appendix B) can be used to determine pollution potential by State.

Table 49. POWER PLANT COAL ASH COMPOSITIONS[116]

Constituent	% by weight
Silica (SiO_2)	30-50
Alumina (Al_2O_3)	20-30
Ferric Oxide (Fe_2O_3)	10-30
Lime (CaO)	1.5-4.7
Potassium Oxide (K_2O)	1.0-3.0
Magnesia (MgO)	0.5-1.1
Sodium Oxide (Na_2O)	0.4-1.5
Titanium Dioxide (TiO_2)	0.4-1.3
Sulfur Trioxide (SO_3)	0.2-3.2
Carbon (C) and volatiles	0.1-4.0
Boron (B)	0.1-0.6
Phosphorus (P)	0.01-0.3
Uranium (U) and Thorium (Th)	0.0-0.1

Table 50. SELECTED TRACE ELEMENTS IN ASH[116]
(ppm)

Element	Fly ash[a]	Bottom ash[a]
Arsenic	15	3
Mercury	0.03	< 0.01
Antimony	2.1	0.26
Selenium	18	1
Cadmium	< 0.5	< 0.5
Zinc	70	25
Manganese	150	150
Boron	300	70
Barium	5000	1500
Beryllium	3	< 2
Nickel	70	15
Chromium	150	70
Lead	30	20
Vanadium	150	70

[a] Actual trace element composition will vary widely depending on boiler type and coal composition.

A review of the technical literature dealing with the suspension of particulate matter by air streams indicates that wind erosion occurs most readily at particle diameters of about 100 microns. Soils with particle diameters less than 50 microns (representative of fly ash) hardly erode at all because of attractive forces between particles.[129] Many laboratory studies further confirm that as particle size decreases below 50 microns, the velocity required to suspend the particle increases.

In view of the above, and considering that most of the ash is transported by water sluicing and initially ponded and that most landfill operations ultimately involve some sort of control measure (soil and vegetative cover), an emission factor of 1 lb/ton of ash was chosen to estimate air emissions from ash handling. The emission factor is appreciably higher (greater than two orders of magnitude) than that for coal storage and handling losses and results in an estimated particulate emission of 20,000 ton/year. Further, it was assumed that all ash is ultimately disposed of as landfill.

COOLING SYSTEM WATER WASTES

Within the steam electric power generating industry, cooling systems are a significant source of both thermal and chemical discharge. Cooling systems are either wet or dry and utilize a once-through or recirculatory flow pattern. Wet systems use water for cooling the working fluid and dry systems use ambient air. Combination wet-dry systems are also in use. In addition to thermal discharges, cooling systems can produce fogging and fallout of salt laden droplets (drift or carry-over). Table 51 summarizes the environmental considerations and potential impacts of various wet cooling systems.[135]

The quantity of cooling water discharge from once-through cooling systems and blowdown from recirculative systems is given in Table 22. The amount of cooling tower makeup, blowdown, evaporation, and drift associated with cooling in a typical 1000 MW power plant is presented in Figure 4.

Table 51. SUMMARY OF ENVIRONMENTAL CONSIDERATIONS AND THE POTENTIAL IMPACT OF WET COOLING SYSTEMS[135]

Atmospheric effects	Hydrologic and aquatic effects	Land effects
Visible plume: visual intrusion, ground shading, and reduction in visibility to various means of transportation. Ground fog: potential hazard to ground and water transportation and nuisance to nearby communities. Icing: potential hazard to ground transportation and ice accumulation on nearby structures and utility wires. Drift deposition: potential damage to biota, acceleration of corrosion of nearby structures, and contamination of soil and water bodies. Cloud formation: visual intrusion and potential local weather modifications. Precipitation and snow augmentation: potential local weather modifications and nuisance to nearby communities and drivers on adjacents roads.	Net water consumptive use: potential depletion of surface-water and groundwater resources and degradation of water quality. Blowdown discharge: potential contamination of surface-water and groundwater supplies, potential increase of soil salinity, and increase of water temperature near discharge point. Seepage and leakage water: same effects as blowdown discharges. Intake screen devices: impingement or entrapment of aquatic life. Transport through condenser and circulation pumps: damage to aquatic organisms. Discharge systems: disturbance to aquatic communities due to mechanical forces and turbulence.	Land use: type of land acquired and the amount area required for each of the cooling systems. Terrestrial impact: potential damage to plant communities and wildlife due to excavation, grading, and construction; effects of drift deposition; and excess moisture on the biota. Land characteristics: effects of seismic risks, soil permeability, and type of foundation or construction required. Other effects Sound levels: nuisance to nearby residents and transient observers. Aesthetics: nuisance to nearby residents and transient observers.

Table 52 presents detailed cooling system wastewater data delineated according to the type of fossil fuel used in individual power plants. The information is reduced from an FPC summary report on steam-electric plant air and water quality as compiled for calendar year 1972.[23] Any plant receiving more than 75 percent of its heat input from a particular fuel was classified according to this primary fuel. Any plant receiving less than 75 percent of its heat input from one particular fuel was classified under its two major fuels. This resulted in a system of six classifications: coal, oil, gas, coal and oil, coal and gas, and oil and gas. All fossil fuel plants are listed by type of cooling system: once-through fresh, once-through saline, cooling ponds, cooling towers, and combination cooling systems. These latter three systems are classified as recirculative. The following data were compiled for each class: number of plants, number of boilers, generating capacity, annual electricity generated, average rate of withdrawal from the cooling water source, average rate of discharge to the cooling water source, amount of cooling water additives, and average low and high temperature rise across the condensers.

Thermal Discharge

The average thermal discharge to water associated with the production of electrical energy in the United States is 5000 Btu/kWh.[136] In 1974, 1419 billion kWh of electricity was produced by fossil fuel external combustion power plants. Based on the national average thermal discharge rate, 7.1×10^{15} Btu of heat was discharged by fossil fuel power plants in 1974. The total heat discharge given in Table 52 is based on data collected for 1972 by the FPC.[23] The total of 6.26×10^{15} Btu corresponds closely with the value of 6.38×10^{15} Btu derived from 1972 fuel consumption and the discharge factors presented above.

Table 52. CHARACTERIZATION OF COOLING SYSTEMS IN THE U.S. - 1972

Cooling system	No. plants	No. boilers	Total capacity, MW	Annual (1972) electricity generated, MWh x 10^6	Continuous withdrawal rate, ft^3/s	Discharge rate, ft^3/s	Chlorine, tons	Average low ΔT, °F	Average high ΔT, °F	Annual heat discharged (calculated), Btu/yr x 10^{12}
Once-through										
Fresh										
Coal	189	716	91,662	461.0	97,687	97,421	6,890	15.03	17.08	3,086
Oil	19	80	6,571	34.0	9,070	9,057	1,102	11.53	15.74	243
Gas	41	162	12,793	50.2	12,724	12,673	194	14.07	16.49	381
Gas and oil	16	97	2,542	10.8	4,487	4,479	207	11.63	13.75	112
Gas and coal	44	234	14,781	71.0	14,257	14,236	2,188	13.11	16.34	412
Coal and oil	6	124	6,434	5.9	1,633	1,633	142	13.83	17.17	49
Saline										
Coal	12	29	5,060	23.8	6,782	6,782	1,747	12.18	15.83	186
Oil	61	375	23,114	105.0	27,948	27,475	4,460	12.23	16.21	782
Gas	25	114	11,994	49.4	10,494	10,484	1,515	14.08	18.40	335
Gas and oil	21	103	15,463	72.5	18,063	18,063	0	14.76	17.10	566
Gas and coal	0	0	0	0	0	0	0	0	0	0
Coal and oil	6	23	3,553	15.8	4,713	4,713	1,182	11.67	13.00	114
Total: Once-through	440	2,057	285,999	899.4	207,856	207,513	19,627			6,266

Table 52 (continued). CHARACTERIZATION OF COOLING SYSTEMS IN THE U.S. - 1972

Cooling system	No. plants	No. boilers	Total capacity, MW	Annual (1972) electricity generated, MWh x 10^6	Makeup withdrawal rate, ft^3/s	Blowdown discharge rate, ft^3/s	Phosphate, tons	Caustic soda, tons	Lime, tons	Alum, tons	Chlorine, tons[a]	Average low ΔT, °F	Average high ΔT, °F
Recirculative													
Cooling ponds													
Coal	14	33	7,454	40.8	2,661	2,597	-	-	-	-	249	16.5	17.3
Oil	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas	25	82	11,688	47.7	4,918	3,653	0	0	0	0	271	13.7	17.2
Gas and oil	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas and coal	1	9	282	0.8	14	8	0	0	0	0	1	10	10
Coal and oil	-	-	-	-	-	-	-	-	-	-	-	-	-
Cooling towers													
Coal	20	46	13,517	53.7	294	105	87	178	6,726	819	334	21.07	21.03
Oil	1	3	252	0.1	5	0	30	0	0	0	36	11	13
Gas	85	279	17,176	7.0	477	161	415	3	6,584	295	1,081	14.88	17.16
Gas and oil	8	32	1,854	7.2	25	6	27	0	343	216	244	15.63	17.25
Gas and coal	8	21	2,941	8.9	42	7	67	0	1,484	74	153	14.25	17.75
Coal and oil	-	-	-	-	-	-	-	-	-	-	-	-	-
Combined systems[b]													
Coal	23	82	12,256	58.1	9,015	8,963	1	454	2	0	491	18.43	20.74
Oil	1	6	618	2.47	561	561	0	0	0	0	3	14	19
Gas	28	150	9,783	45.2	5,099	5,003	53	1	745	48	1,151	13.96	18.29
Gas and oil	2	10	60	0.1	41	41	0	0	0	688	1	15.0	18.0
Gas and coal	7	26	2,237	10.9	1,929	1,274	0	0	0	0	61	13.86	17.86
Coal and oil	-	-	-	-	-	-	-	-	-	-	-	-	-
Total: Recirculative	223	779	80,114	242.5	25,078	22,379	680	635	15,884	2,140	4,075		

[a] Additives as reported by FPC.

[b] Systems with a capability of using more than one type of cooling unit.

The once-through cooling system is presently the most common method of condenser cooling.[23,137] Once-through systems use an ocean, estuary, river, or lake as their water source. The cooling water is withdrawn and passed through a condenser where it collects heat transferred from the working fluid and then is discharged to the original source. The amount of heat added to the water is dependent upon the thermal efficiency of the condenser and the amount of cooling water. Analysis of data included in the FPC Summary Report[23] indicates an average temperature rise of 15°F and a discharge rate of 2×10^{-5} cubic meters per second per kilowatt of generating capacity. The annual heat discharge to water in total British Thermal Units is presented in Table 52 for once-through cooling systems. Over the range of cool and warm cooling water temperature, the heat capacity of water is constant at 1.0 Btu/lb/F°. Consequently, the heat discharge is equal to water discharge in lbs/yr multiplied by the average temperature change in degrees Fahrenheit. Table 53 presents a summary of thermal water discharges emanating from once-through cooling systems.

The second method of condenser cooling is recirculation of the cooling water.[137] Although existing plants utilize once-through cooling to a large extent, new plants are using recirculative cooling systems in order to reduce thermal discharges as required by the Water Pollution Control Act Amendments of 1972[138] and associated effluent guidelines.[130] Recirculative systems consist of cooling ponds or lakes, spray canals or ponds, wet cooling towers or combination wet-dry cooling towers. Cooling towers are operated using either a natural or mechanical draft.[135] Cooling towers must be blown down in order to prevent buildup of solids and subsequent fouling of condenser surfaces. There is some rejection of heat to surface water due to the heat content of blowdown water. The heat content of the blowdown can vary from under 1 percent of the total condenser heat discharge for cold-side blowdown systems to as high as 7 to 8 percent of the total condenser heat discharge for hot-side blowdown systems.[36] The thermal discharge to water associated with recirculative cooling systems cannot be reliably calculated. Blowdown is generally performed at the

Table 53. THERMAL DISCHARGES TO WATER FROM POWER PLANT COOLING SYSTEMS

		Thermal discharge	
		Once-through fresh, 10^{12} Btu/yr	Once-through saline, 10^{12} Btu/yr
1.0.00.0.0	Electric generation		
1.1.00.0.0	External combustion	4280	1980
1.1.10.0.0	Coal	3320	240
1.1.11.0.0	Bituminous	3220	230
1.1.11.1.0	Pulverized dry	2330	170
1.1.11.2.0	Pulverized wet	430	29
1.1.11.3.0	Cyclone	430	29
1.1.11.4.0	All stokers	30	2
1.1.12.0.0	Anthracite	20	2
1.1.12.1.0	Pulverized dry	7	1
1.1.12.2.0	Pulverized wet	0	0
1.1.12.3.0	Cyclone	0	0
1.1.12.4.0	All stokers	13	1
1.1.13.0.0	Lignite	80	8
1.1.13.1.0	Pulverized dry	48	5
1.1.13.2.0	Pulverized wet	12	1
1.1.13.3.0	Cyclone	12	1
1.1.13.4.0	All stokers	8	1
1.1.20.0.0	Petroleum	320	1120
1.1.21.0.0	Residual oil	300	1070
1.1.21.0.1	Tangential firing	120	420
1.1.21.0.2	All other	180	650
1.1.22.0.0	Distillate oil	20	50
1.1.22.0.1	Tangential firing	8	20
1.1.22.0.2	All other	12	30
1.1.30.0.0	Gas	640	620
1.1.30.0.1	Tangential firing	160	150
1.1.30.0.2	All other	480	470

cold side of the cooling system so that the temperature difference between blowdown and ambient water is minimal. If blowdown were performed on the hot side of all recirculative systems, the total heat discharge would be a maximum of 11 percent of that associated with once-through systems as defined by the total water discharge in each system.

The ambient atmosphere is the ultimate receptor of heat dissipated from once-through and recirculative cooling systems. The significance of atmospheric thermal pollution from these sources has not been investigated but is negligible in comparison to the solar input.

Wastewater Discharge

The quantity and quality of cooling water discharge depends upon the type of cooling system in use. For example, Federal regulations require that the quantity of free available chlorine discharged from once-through cooling systems will not exceed 0.5 mg/ℓ on the average over 30 days. On the other hand the regulations[130] state that the quantity of pollutants discharged with recirculative cooling system blowdown will not exceed the concentrations enumerated below:

Pollutant	1-day maximum concentration	30-day average concentration
Free available chlorine	0.5 mg/ℓ	0.2 mg/ℓ
Zinc	1.0 mg/ℓ	1.0 mg/ℓ
Chromium	0.2 mg/ℓ	0.2 mg/ℓ
Phosphate	5.0 mg/ℓ	5.0 mg/ℓ
Other corrosion inhibiting materials	Limit to be established on a case-by-case basis	

In addition to these regulations, power plants are required to submit an application for a National Pollution Discharge Elimination System (NPDES) Permit to the Regional EPA Administrator and State. If the effluent characteristics and levels outlined in this NPDES Application are fundamentally different from those outlined by Federal regulations and those considered in the guideline development document;[36] and if these differences are deemed justifiable, the Regional Administrator or state can establish effluent limitations in the NPDES permit either more or less stringent than those outlined in the above Federal regulations. Such limitations must be approved by the Administrator of the Environmental Protection Agency.[130-134]

Once-Through Systems - Passage of water through condensers and service water coolers causes growth and accumulation of biological organisms on cooling system surfaces. The troublesome organisms are primarily algae and bacteria, although in saline cooling systems they include higher level organisms. The uncontrolled buildup of these organisms can greatly reduce the efficiency of the condenser. The most commonly employed method of removing these organisms is the intermittent injection of chlorine or sodium hypochlorite into the cooling water system.[136]

The amount of chlorine dosage varies from site to site and depends upon the source of cooling water and ambient conditions. For example, in winter the biological growth is not as extensive as in spring or summer, and the chlorine demand is low. Normally, the chlorine is supplied as a slug rather than by continuous injection. The frequency of chlorine dosage differs in each plant, and may vary from once a day to as many as 12 times a day with the treatment duration varying between 5 minutes and 2 hours. Chlorination results in residual chlorine concentrations in the range of 0.1 to 1.0 mg/ℓ. Higher residual concentrations are required when treating saline water cooling systems. Residual chlorine levels of 4.0 to 5.0 mg/ℓ are necessary for removal of crustaceans.[36,137]

Recirculative Systems - Warm recirculating water is cooled by evaporating a fraction of the total volume. During the cooling process, a small percentage of the water will be suspended in the air draft as water vapor and entrained droplets (drift) will be emitted. As a result of evaporative cooling water losses, salts that are dissolved in the remaining cooling water become more concentrated.[36,139] Most natural waters contain calcium (Ca^{++}), magnesium (Mg^{++}), sodium (Na^{+}), other metallic ions, and carbonate (CO_3^{--}), bicarbonate (HCO_3^{-}), sulfate (SO_4^{--}), chloride (Cl^{-}), and other acid ions in solution.[36,140] In addition seawater contains high concentrations of sodium (Na^{+}) and chloride (Cl^{-}).

As cooling water evaporates, all constituents, including dissolved and suspended solid materials, are concentrated in the cooling stream. The degree to which these constituents can be concentrated is limited by the solubility of the constituents for the prevailing conditions of temperature and pH. Additives are introduced into recirculating cooling water streams to control corrosion and scale and the formation of algae, slime, and fungi. Tables 54, 55, and 56 list some of the additives and additive systems that are used and the concentrations of ions and biocides in these systems that are discharged with blowdown. Reference should be made to Table 24 which lists trace element concentrations in cooling tower blowdown. The values represent a single specific plant and are not intended to be national averages. The power plant studied was tangentially-coal-fired with a total capacity of 750 MW.

Calcium carbonate and calcium sulfate are the dissolved salts of greatest concern in cooling tower systems. In the Southwest, silica and silicates also present a problem. At high concentrations, these materials exceed their solubility limit, precipitate out of solution and deposit on heat exchanger surfaces as a hard scale. Removal of a portion of cooling water (blowdown) and replacement with fresh makeup cooling water is one method used to reduce the concentration of these troublesome materials. Temperature, pH, and chemical additives are factors which affect the solubility of these materials. Some additives which are used to increase the solubility of these materials are organic phosphates, phosphonates, polymers, and sulfuric acid.[137]

Table 54. CHEMICALS USED IN RECIRCULATIVE COOLING WATER SYSTEMS[140]

Use	Chemical
Corrosion inhibition or scale prevention in cooling towers	Organic phosphates Sodium phosphate Chromates Zinc salts Synthetic organics
Biocides in cooling towers	Chlorine Hydrochlorous acid Sodium hypochlorite Calcium hypochlorite Organic chromates Organic zinc compounds Chlorophenates Thiocyanates Organic sulfurs
pH control in cooling towers	Sulfuric acid Hydrochloric acid
Dispersing agents in cooling towers	Lignins Tannins Polyacrylonitrile Polyacrylamide Polyacrylic acids Polyacrylic acid salts
Biocides in condenser cooling water systems	Chlorine Hypochlorites Sodium pentachlorophenate

Table 55. COOLING TOWER CORROSION AND SCALE INHIBITOR SYSTEMS[23]

Inhibitor system	Concentration of chemical additives in recirculating water, mg/ℓ
1. Chromate	200 - 500 mg/ℓ $CrO_4^{=}$
2. Chromate + Zinc	17 - 65 mg/ℓ $CrO_4^{=}$ 8 - 35 mg/ℓ Zn^{++}
3. Chromate + Zinc + Phosphate (inorganic)	10 - 15 mg/ℓ $CrO_4^{=}$ 8 - 35 mg/ℓ Zn^{++} 30 - 45 mg/ℓ $PO_4^{\equiv}$
4. Zinc + Phosphate (inorganic)	8 - 35 mg/ℓ Zn^{++} 15 - 60 mg/ℓ $PO_4^{\equiv}$
5. Phosphate (inorganic)	15 - 60 mg/ℓ $PO_4^{\equiv}$
6. Phosphate (organic)	15 - 60 mg/ℓ $PO_4^{\equiv}$ 3 - 10 mg/ℓ organics
7. Organic Biocide	30 mg/ℓ chlorophenol 5 mg/ℓ sulfone 1 mg/ℓ thiocyanate

Table 56. TYPICAL COOLING TOWER ADDITIVE SYSTEMS[36]

Chromate - inorganic phosphate system

Untreated river water makeup to tower	Cooling tower system
80 mg/ℓ Ca^{++}	320 mg/ℓ Ca^{++}
16 mg/ℓ Mg^{++}	64 mg/ℓ Mg^{++}
157 mg/ℓ HCO_3^-	18 mg/ℓ HCO_3^-
455 mg/ℓ Cl^-	1,820 mg/ℓ Cl^-
60 mg/ℓ $SO_4^=$	712 mg/ℓ $SO_4^=$
	27 mg/ℓ $CrO_4^=$
	12 mg/ℓ $PO_4^=$
	pH 6.5

Controllable limits in tower system: pH 6.4 to 6.6; total alkalinity 15 to 20 mg/ℓ; calcium as $CaCO_3$ 1,000 mg/ℓ max; hexametaphosphate 6 to 10 mg/ℓ; CrO_4 25 to 30 mg/ℓ.

Organic phosphate system

Untreated well water makeup to tower	Cooling tower system
80 mg/ℓ Ca^{++}	333 mg/ℓ Ca^{++}
10 mg/ℓ Mg^{++}	52 mg/ℓ Mg^{++}
263 mg/ℓ HCO_3^-	239 mg/ℓ HCO_3^-
28 mg/ℓ SiO_2	150 mg/ℓ SiO_2

Controllable limits in tower system: pH 8.4 to 8.6; total alkalinity 175 to 225 mg/ℓ; calcium as $CaCO_3$ 1,000 mg/ℓ max; silica as SiO_2 180 mg/ℓ max; organic phosphate 20 to 30 mg/ℓ.

The wet warm conditions present in recirculating cooling systems promote microbial growth, and the uncontrolled growth of algae, slimes, and fungi in the main condenser and other heat exchangers may be a serious problem. As in once-through systems, chlorine is used to inhibit the growth of algae and slimes. Residual chlorine concentrations are maintained below 1.0 mg/ℓ to avoid corrosion problems. Sodium pentachlorophenate is also used to stop fungi attacks.[137]

Ions in cooling water may be naturally occurring or introduced as corrosion inhibitors, biocides, pH controls and dispersants. When the concentration of these ions exceeds solubility limits, salt will precipitate. The solubility of some salts decreases when the temperature rises. Salts exhibiting this characteristic are likely to precipitate and form scale on hot condenser tube walls and reduce heat transfer. The most common way to control this scale formation is to blowdown a portion of the recirculating water stream and replace it with fresh water so that the ion concentration in the circulating water does not reach saturation at any time. Blowdown (B) is a function of cooling water makeup quality. As shown in the following equation, the volume of cooling water makeup (M) required is equal to the sum of the volume of cooling water lost as blowdown (B), drift (D), evaporation (E), and seepage or leakage (S).[36,135]

$$M = B + D + E + S$$

S is very small in comparison to the other volume parameters and can be neglected without significantly affecting calculated volumes. It follows that the volume of blowdown is a function of makeup water quality and can be determined from the following expression.[36]

$$B = \frac{E - (S + D)\ (C - 1)}{C - 1}$$

where C = cycles of concentration (dimensionless).

Cycles of concentration is the number of times that the solute species can be concentrated before one particular constituent concentration exceeds a critical level. C can be increased as influent water quality increases. This qualitatively illustrates the degree to which influent water quality can degrade prior to falling below acceptable levels. The equation shows that for a constant rate of evaporation, drift and seepage the required blowdown decreases as C increases. The equation represents a tradeoff between external feedwater treatment and internal chemical conditioning needs. For average quality cooling water makeup, the value for C is conventionally kept between 4 and 6. For extremely high quality cooling water makeup, C values of 15 and above may be employed. When saline cooling water is used, C generally ranges between 1.2 and 1.5. Figure 17 presents a recently published nomograph for computing cooling tower blowdown and makeup requirements.[141]

Environmental Impacts of Recirculative Cooling Systems

The significant environmental quality impacts associated with recirculative cooling systems are drift, fogging and consumptive water use. Table 57 illustrates the relative environmental impacts produced by these systems.

Drift - Droplets of water may be discharged from spray cooling canals or ponds, wet cooling towers, and wet-dry cooling towers. The warm moist air discharged from cooling towers contains mechanically entrained water droplets which range from several microns to several hundred microns in diameter. Droplets smaller than approximately 20 microns are referred to as fog, while larger droplets are commonly called drift or carry-over. In contrast to fog, which is relatively pure condensed water vapor, drift droplets contain the same concentration of dissolved chemicals as the circulating cooling water stream.[142,143] Table 58 presents the design and operational characteristics of wet cooling systems that affect drift rates.

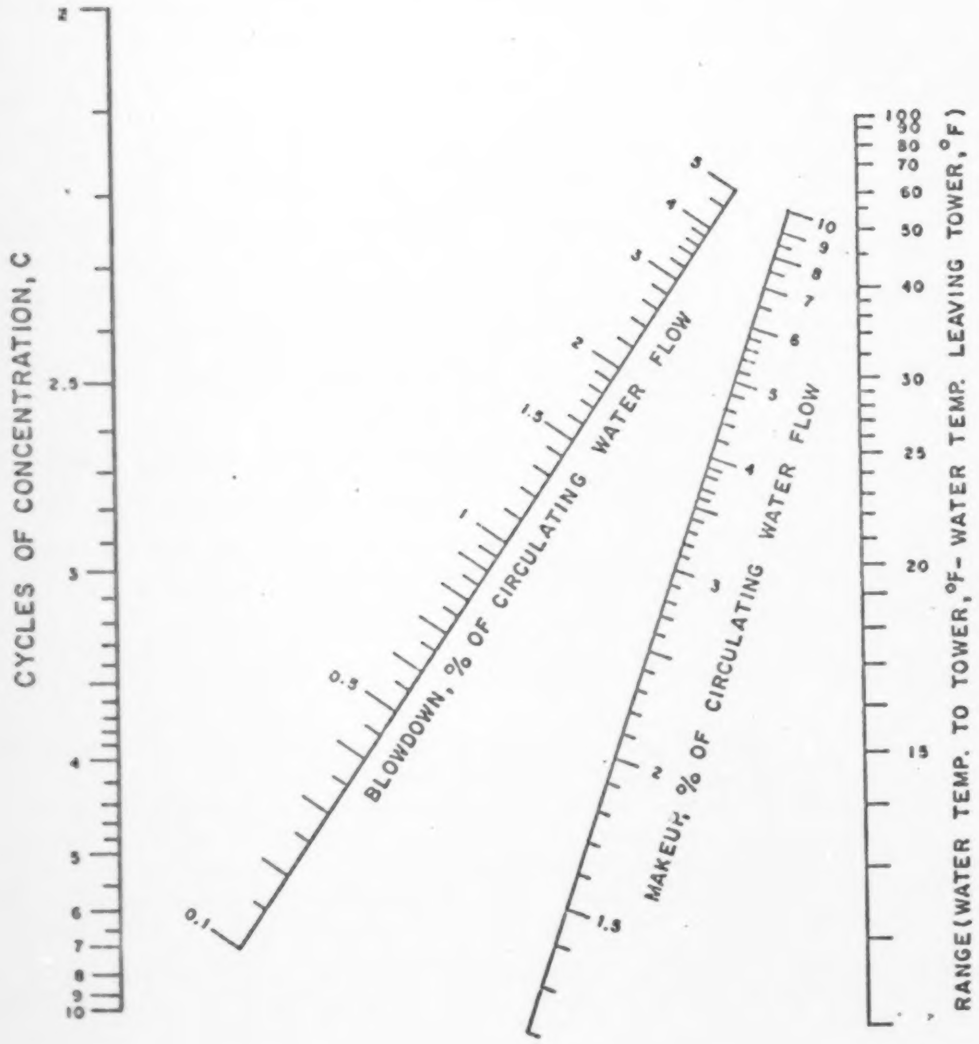

Figure 17. Nomograph for computing cooling tower blowdown and makeup requirements[141]

Table 57. RELATIVE ATMOSPHERIC IMPACT OF VARIOUS RECIRCULATIVE COOLING SYSTEMS[142]

Relative environmental impact	Type of impact			
	Visible vapor plume	Ground fog	Icing	Drift deposition rate
Most severe	C[a]	D	D	D
Intermediate effect	A,B,D	A,B,C	A,B,C	B,C,E
Least severe	E	E	E	A

[a] Type of cooling systems:
A - Cooling lake
B - Spray pond
C - Natural draft wet cooling tower
D - Mechanical draft wet cooling tower
E - Mechanical draft wet-dry cooling tower.

Table 58. DESIGN AND OPERATIONAL CHARACTERISTICS OF WET COOLING SYSTEMS AFFECTING DRIFT RATES[142]

Cooling towers	Spray canals or ponds
Volume of circulating water in the system per unit time	Volume of circulating water in the system per unit time
Tower features (height, diameter, and characteristics of drift eliminators for natural-draft tower; height, cell diameter, characteristics of drift eliminators, and number of cells for mechanical draft tower)	Area, spray modules spacing, and spray nozzle characteristics (droplets size and spray pattern)
Drift flux and droplet size distribution	Drift flux and droplet size distribution
Exit temperature	Spray nozzle exit temperature
Exit velocity	Spray nozzle exit velocity

Evaporation causes the concentration of dissolved solids in the drift droplets to increase.[134] The reduction in droplet size decreases fall speed, and as drift droplets fall out of the plume they are dispersed by atmospheric turbulence.[139] Table 59 presents the atmospheric variables and characteristics that affect the dispersion and deposition of drift.[142] Smaller drift particles possess lower inertia and are dispersed more efficiently.[139] Figure 18 illustrates a typical distribution for cooling tower drift fallout,[144] and Figure 19 presents drift deposition rates from three different types of wet cooling systems for two different atmospheric conditions.[145]

Table 59. ATMOSPHERIC VARIABLES AND CHARACTERISTICS AFFECTING DISPERSION AND DEPOSITION OF DRIFT[142]

Atmospheric variables	Atmospheric characteristics
Ambient temperature	Atmospheric stability
Ambient relative humidity	Depth of the mixing layer
Wind speed and direction	
Precipitation (rain and snow)	
Concentration of condensation nuclei	

Recirculative cooling system drift losses may vary from 0.005 percent to 0.02 percent of the cooling flow for well controlled natural draft and mechanical draft cooling towers.[36] Drift eliminators are often used to control drift emissions from cooling towers.[144] Figure 20 illustrates cooling tower drift deposition rates for two eliminator systems and two sets of atmospheric conditions[145] and Table 60 presents measured and estimated drift deposition values as reported in various references. An emission factor based on generating capacity would be totally unreliable due to the large number of variables influencing deposition.

Spray cooling ponds produce higher drift rates than cooling towers but the maximum radial distance of discharge is substantially reduced.[36] The drift rate is typically 0.1 percent of cooling water flow and the highest

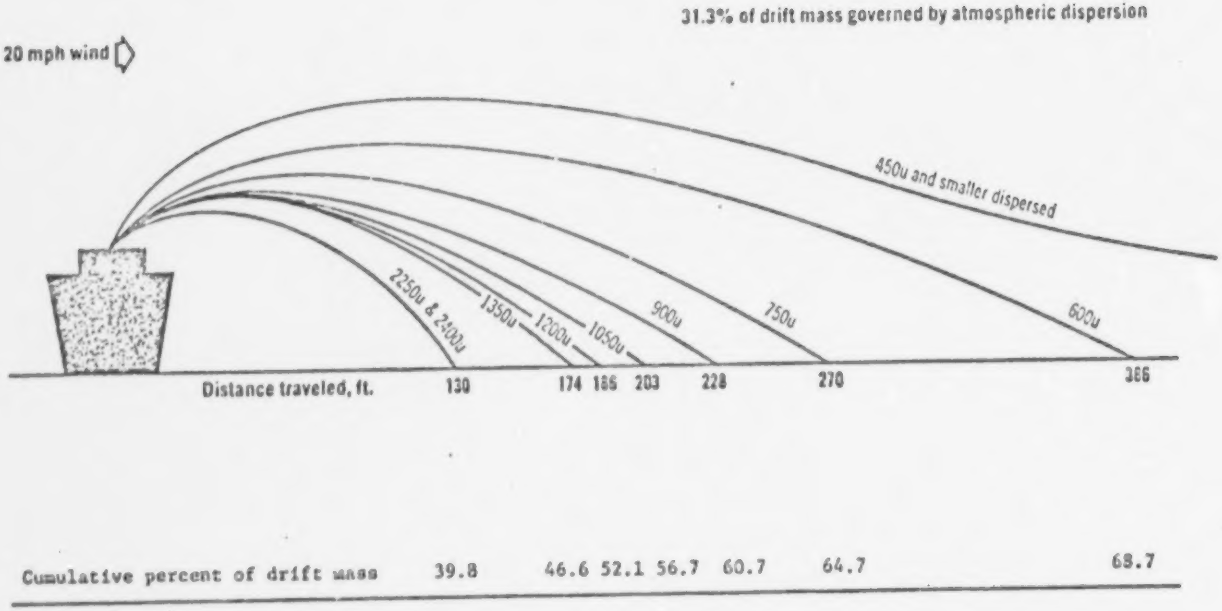
31.3% of drift mass governed by atmospheric dispersion
20 mph wind
450u and smaller dispersed
2250u & 2400u
1350u
1200u
1050u
900u
750u
600u
Distance traveled, ft.
130
174
186
203
228
270
386
Cumulative percent of drift mass
39.8
46.6
52.1
56.7
60.7
64.7
68.7

Figure 18. Cooling tower drift fallout (from reference 144)

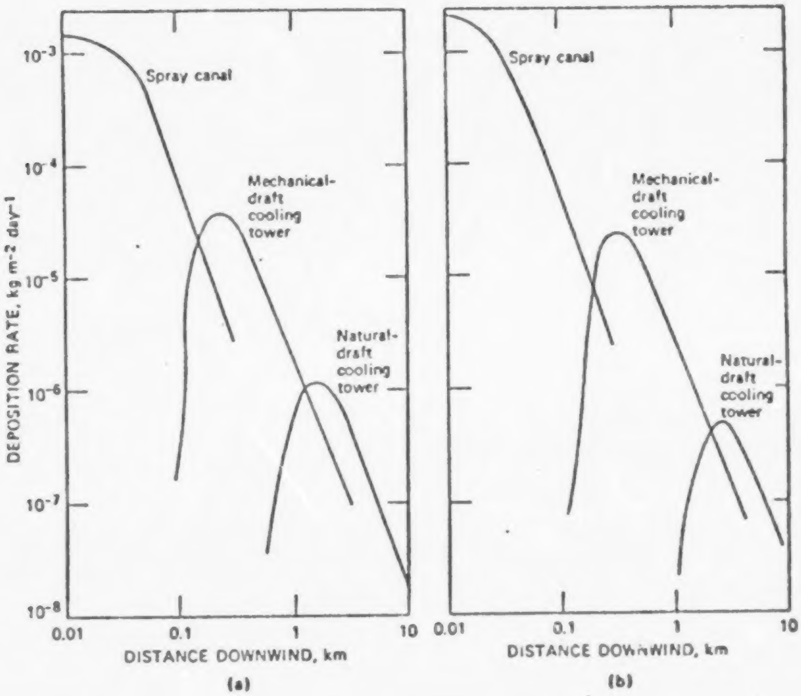

Figure 19. Drift deposition rates from wet cooling systems as a function of the distance downwind under (a) slightly unstable atmospheric conditions - ambient temperature of 7.2°C, relative humidity of 95 percent; and (b) neutral atmospheric conditions - ambient temperature of 7.2°C, relative humidity of 95 percent (From reference 145)

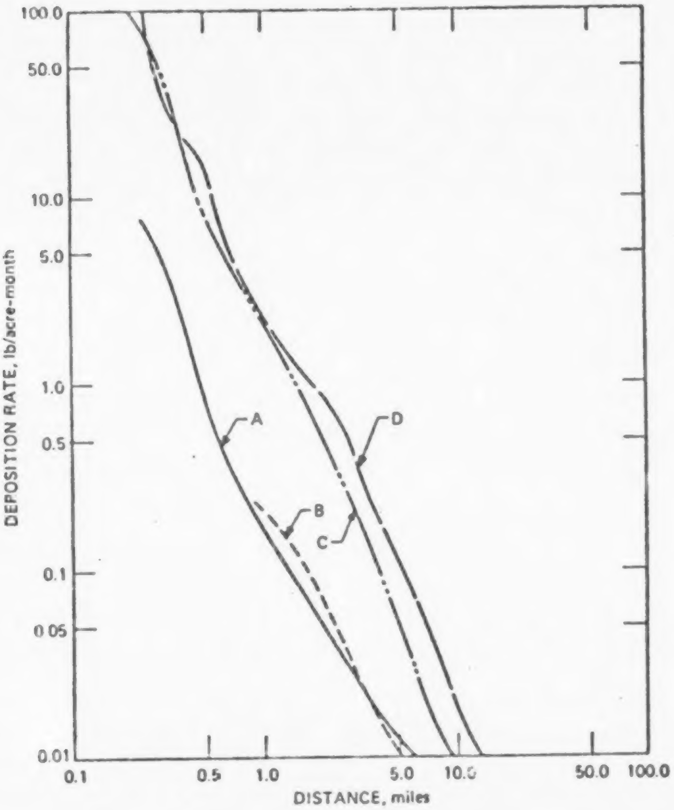

Figure 20. Drift deposition rates for two eliminator systems and two sets of atmospheric conditions: A - duplex eliminator, stable, 90 percent relative humidity, 2.5 mph wind; B - duplex eliminator, unstable, 60 percent relative humidity, 10 mph wind; C - sinusoidal-wave eliminator, stable, 90 percent relative humidity, 2.5 mph wind; and D - sinusoidal-wave eliminator, unstable, 60 percent relative humidity, 10 mph wind (From reference 145)

Table 60. SALT DEPOSITION RATES

Measured or predicted	Type of tower or model used	Plant capacity, MW	Salt or fresh water cooling	Maximum deposition, lb/acre/yr	Distance to maximum deposition, feet	Total deposition[a]		
						lb/yr	ton/yr	ton/MW
Measured	Mech. draft wet tower - Anclote Plant, Florida	2 at 515	Salt	194.0	5,000	3.5×10^5	1.75×10^2	0.17
Measured	Natural draft wet tower - Seabrook, N.H.		Salt	65.6	16,000	3×10^6	1.5×10^3	
Measured	Trojan Nuclear Plant		Fresh	1.3				
Predicted[b]	Natural draft Diffusion Model Roffman & Grimble[c]	1000	Salt	27.6	2,600	1.3×10^4	6.5	0.01
Predicted[b]	Natural draft Hosler Method[d] Hosler et al.	1000	Salt	348	3,900	3.8×10^5	1.9×10^2	0.19
Measured[e]	Mechanical draft	1320	Salt			3.8×10^7	1.9×10^4	14.4
	Mechanical draft	1644	Fresh			6×10^5	3×10^2	0.18
	Mechanical draft	1722	Fresh			10.5×10^5	5.25×10^2	0.30
	Mechanical draft	821	Fresh			4.7×10^4	23.5	0.03
	Natural draft	873	Fresh			1.1×10^6	5.5×10^2	0.63
	Natural draft	850	Fresh			4×10^5	2×10^2	0.24
	Natural draft	872	Fresh			9×10^4	45	0.05

[a] These figures represent deposition within the area bounded by the distance to maximum deposition. This provides a basis for comparison with the figures given in footnote e.

[b] A. Roffman and L. D. Van Vleck, "The State-of-the-Art of Measuring and Predicting Cooling Tower Drift and Its Deposition," Journal of APCA. September 1974, p. 855-859.

[c] A. Roffman and R. E. Grimble, "Prediction of Drift Deposition from Salt Water Cooling Towers." The Annual Meeting of Cooling Tower Institute, Houston, Texas, January 29 to 31, 1973.

[d] C. Hosler, J. Pena, and R. Pena, "Determination of Salt Deposition Rates from Drift from Evaporative Cooling Towers." Dept. of Meteorology, Penn. State Univ., 1972.

[e] Development Document for Effluent Limitations Guidelines and New Source Performance Standards for Steam Electric Power Generating Point Source Category. EPA 440/1-74-029a. October 1974.

salt deposition occurs at approximately 300-400 feet from the source.[139] One reference reports that the composite of a number of tests at various spray cooling sites indicates that measurable drift rarely exceeds 600 feet from the source under a variety of meteorological conditions.[182]

Fogging - Plumes from cooling towers have the potential to produce conditions of fogging and icing. Normally the plume will mix with the ambient air and not inhibit visibility. However, during thermal inversions and periods of high humidity and low temperature, the plume can become constrained close to the ground surface and cause fogging. Such fogging is generally limited to the cooling tower site (within ~2000 feet of the tower) and the probability of occurrence is higher with mechanical draft than natural draft cooling towers.[147]

The impact of cooling tower fogging depends upon the duration, frequency, and location of individual incidents. The greatest potential hazard exists in regions of transportation such as airports and major highways. Figure 21 illustrates areas in the U.S. that would be affected by fogging generated from cooling towers. The map is based on the following criteria:[148]

- High Potential - Regions where naturally occurring heavy fog is observed over 45 days per year, where the maximum mixing depths are low (400-600 meters) from October through March, and the frequency of low-level inversions is at least 20-30 percent.

- Moderate Potential - Regions where naturally occurring heavy fog is observed over 20 days per year, where the maximum mixing depths are less than 600 meters from October through March, and the frequency of low-level inversions is at least 20-30 percent.

- Low Potential - Regions where naturally occurring heavy fog is observed less than 20 days per year, and the maximum mixing depths are moderate to high (generally greater than 600 meters) from October through March.

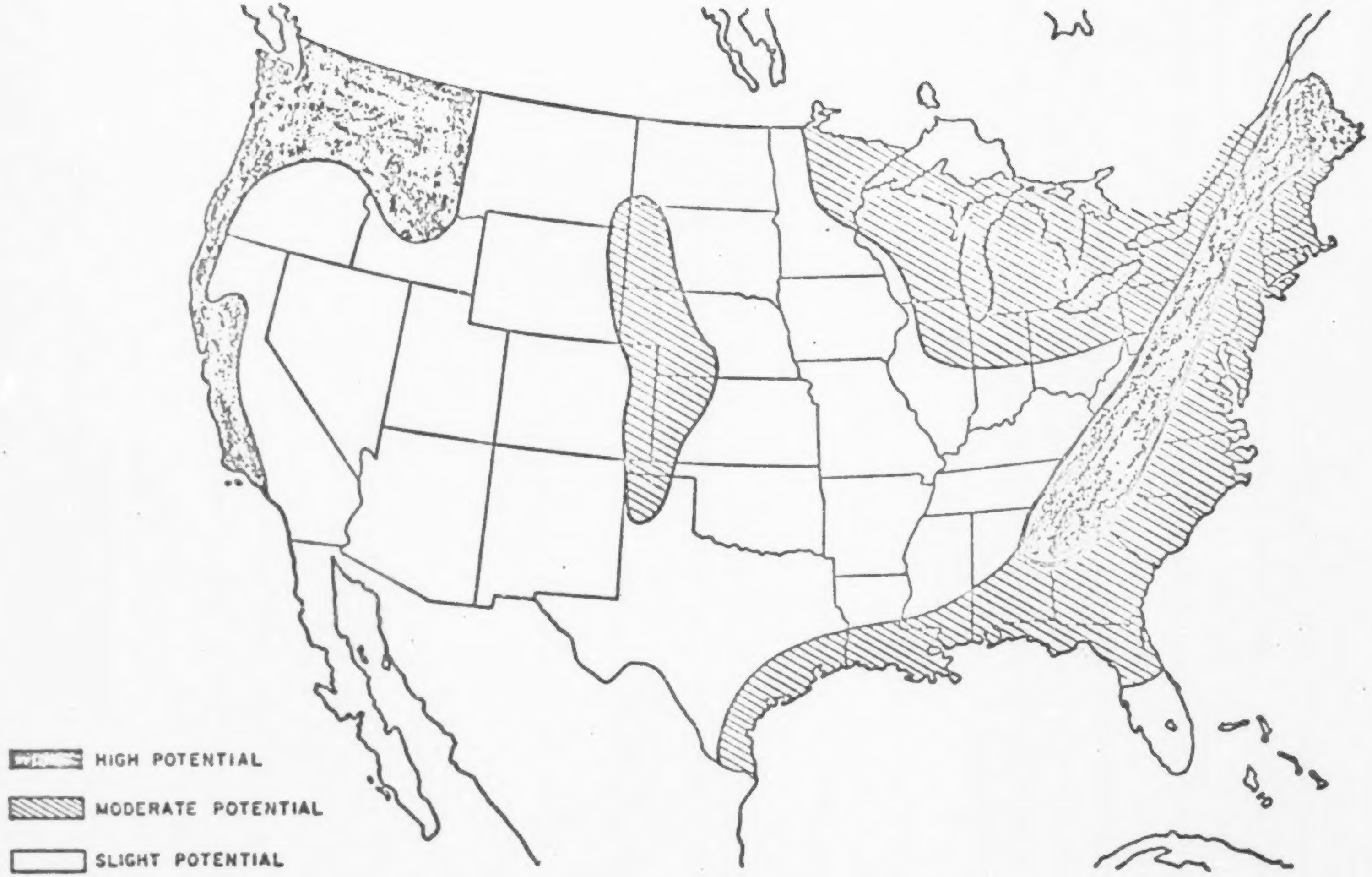
HIGH POTENTIAL
MODERATE POTENTIAL
SLIGHT POTENTIAL

Figure 21. Geographical distribution of potential adverse effects from cooling towers, based on fog, low-level inversion and low mixing depth frequency [148]

Cooling ponds are also a potential source of ground fogging. The development of plumes is not a problem because of the large area of water vapor discharge. A steam type fog can develop over the pond surface during cold weather.[149] The fog produced does not normally extend over the surrounding land, but under extreme conditions may encroach upon bordering land for distances up to 1 mile.[147] In addition, steam fogs can cause icing of embankment vegetation. The extent and effect of cooling pond fogging increases as air temperature decreases, humidity increases, and atmospheric stability increases.

Consumptive Water Use - Recirculative cooling systems transfer heat to the atmosphere through evaporation of a portion of the cooling water. Such recirculative cooling systems consume more water per kWh of electricity produced than do once-through cooling systems. Figures 22, 23, and 24 illustrate the variation in water evaporation as influenced by water temperature, wet bulb temperature and relative humidity.

OTHER WASTEWATER EMISSIONS

The following subsections discuss the wastewater effluents from boiler water treatment, boiler blowdown, and equipment cleaning.

Boiler Water Treatment

The most comprehensive national survey of waste water generated by steam-electric power plants was conducted by the Federal Power Commission and includes general characteristics such as volume, solids loading, and pH. Table 61 summarizes the pertinent boiler feedwater information gathered by the FPC.[23]

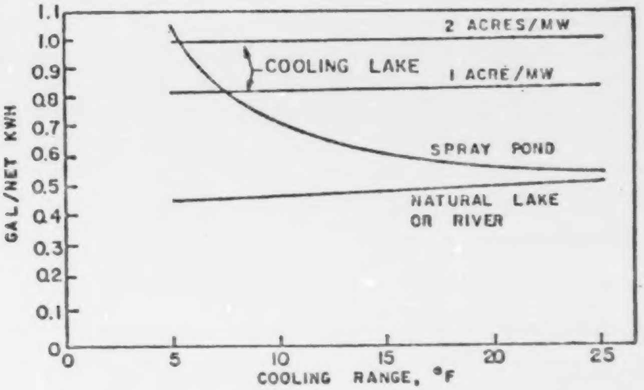

Figure 22. Water consumption versus temperature range of cooling water source[136]

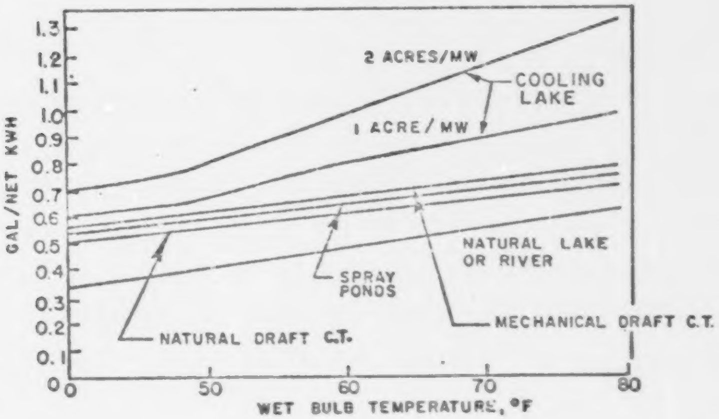

Figure 23. Water consumption versus wet bulb temperature[136]

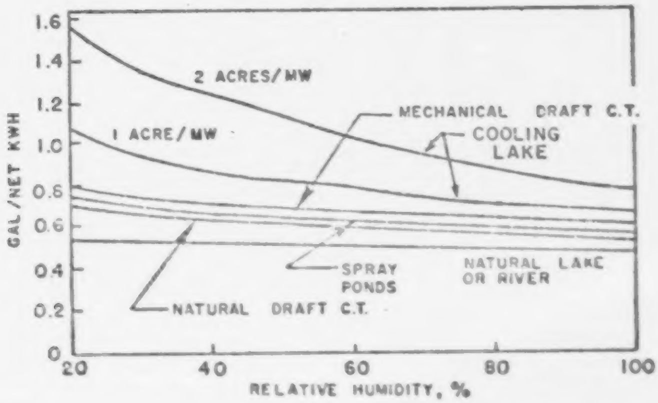

Figure 24. Water consumption versus relative humidity[136]

Table 61. BOILER FEEDWATER REQUIREMENT AND USE OF FEEDWATER TREATING AND CONDITIONING CHEMICALS - 1971 U.S. FOSSIL-FUELED STEAM-ELECTRIC POWER PLANTS[23]

Total annual generation of plants reporting annual boiler feedwater consumption rates	1,260,490,574 MWh/yr
Feedwater requirement	9,000,000,000 gal/yr
Phosphate consumption	973.5 tons/yr
Caustic consumption	43,329.3 tons/yr
Lime consumption	8,662.3 tons/yr
Alum consumption	1,922.5 tons/yr
Chlorine consumption	370.7 tons/yr

Boiler Feedwater Quality Requirements - Boilers in steam-electric power generating stations require that makeup water be added to steam condensate return in order to compensate for feedwater lost during boiler blowdown, steam sootblowing, venting, gland, and boiler tube leakage. The required quantity and quality of all feedwater is a function of boiler operating pressure and heat transfer rate. Modern high pressure boilers require extremely pure feedwater while low pressure boilers (<300 psi) can sometimes operate using feedwater which has not been externally treated. Table 62 is a catalogue of power plant ambient water quality and required boiler feedwater quality as reported in a number of references. The specifications for individual characteristics sometimes vary by an order of magnitude or more. Requirements for boiler feedwater quality are currently under investigation and subject to revision. In addition, the A.S.M.E. Research Committee on Water in Thermal Power Systems is currently investigating and developing a consensus of proper operating practices for industrial boilers.[151] Their preliminary estimates covering values for boilers operating at steam pressures of 1500 psig and greater are shown in Table 62.

Table 62. UTILITY BOILER WATER QUALITY[a]

Characteristic	Ambient water quality				Boiler feedwater quality						
					All boilers				Drum type boilers		Water tube boilers
	Saline	Fresh			NAS[b]		ABMA[f]	Power[g]	Babcock & Wilcox[h]		ASME[i]
	NAS[b]	Strauss[c]	Burns & Roe[d]	EPA[e]	700-1500 psi	1500-5000 psi	1500-2000 psi	>2000 psi	1000-2000 psi	>2000 psi	1500-2000 psi
Alkalinity ($CaCO_3$)	500				40	1	150	100	50-150		
Aluminum	3				0.1	0.1					
Ammonia					0.1	0.07					
Bicarbonate	600				48.0	0.5					
Calcium			16-80		0.01	0.01					
Chloride	19,000		10-150								
COD	500				1.0	1.0					
Copper				0.01	0.05	0.01			0.005	0.002	0.01
DO					0.007	0.007			0.007	0.007	
Dissolved solids	35,000				200.0	0.5					
Hardness ($CaCO_3$)	5,000				0.07	0.07			0	0	0
Hydrogen sulfide											
Iron	80	<15	0.2-2	0.05	0.5	0.01			0.01	0.01	0.01
Magnesium			2.5-12		0.01	0.01					
Manganese	10	<15	0.1-1.0	0.03	0.01	0.01					
Organics	10-100				0.5	0.1	0	0	0	0	
pH, units			5.5-7.5		8.2-9.0	8.8-9.4			8.5-9.5	8.5-9.5	
Phosphate	50										
Silica	150	1-100	2.15		0.7	0.01	1.0	0.5	0.5-5.0	0.15-0.5	
Sulfate	1,400		20-140								
Suspended solids	15,000		10-200		0.5	0.05	10	5			
Total solids	40,000		200-300				750	500	0.15	0.05	
Zinc				0.06	0.01	0.01					

Table 62 (continued). UTILITY BOILER WATER QUALITY[a]

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[a] Values in mg/ℓ unless otherwise noted.

[b] Water Quality Criteria, 1972. A Report of the Committee on Water Quality Criteria, Environmental Studies Board. National Academy of Sciences, National Academy of Engineering. Washington, D.C. 1972.

[c] Strauss, Sheldon D. Water Treatment. Power. June 1973.

[d] Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam-Electric Power Generating Point Source Category. U.S. Environmental Protection Agency. October 1974.

[e] Proposed Water Quality Information. U.S. Environmental Protection Agency, Volume II. October 1973. (Numbers given are averages for various drainage basins throughout the United States.)

[f] Packaged Firetube Boiler Engineering Manual. First Edition. Prepared by Technical Committee of Packaged Firetube Section. American Boiler Manufacturers Association. 1971.

[g] Steam Generation. Power Magazine, 330 West 42nd Street, New York, New York. June 1964.

[h] Steam/Its Generation and Use. Babcock and Wilcox, New York, New York.

[i] Industrial Boiler Water Subcommittee - A.S.M.E. Research Committee on Water in Thermal Power Systems. Feedwater Quality in Modern Industrial Boilers. A consensus of Proper Current Operating Practices. April 1975. PRELIMINARY REPORT.

Categorization of water specifications according to type of fuel use is not provided in the data presented in Table 62; however, oil firing generates the greatest amount of radiant heat and, therefore, demands strictest attention to water quality guidelines. Coal firing releases the next greatest amount of radiant heat and gas firing emits the least.[151] At high operating steam pressures characteristic of utility boilers it is advised that no allowance be made for the type of fuel fired in order to ensure proper boiler operation. As an aid to the discussion of boiler water treatment, the typical steam generating boiler water cycle is shown in Figure 25.

Boiler Water Quality Control - Utility boilers must be continuously monitored in order to provide for efficient operation. This precaution allows for immediate system stabilization and prevention of equipment damage which might result from the use of boiler water containing hazardous contaminants.

Continuous analysis of boiler water specific electrical conductance is the widely used method of automatic monitoring. Conductance is directly proportional to the ionizable dissolved solids in the water. The monitors can be designed to sound alarms or automatically feed back to corrective treatment mechanisms. Specific conductance is measured in micromhos/cm (1×10^{-6} mhos/cm). Utility boilers should contain water which maintains a specific conductance between 0.2 and 0.5 micromhos/cm corresponding to a total dissolved solids concentration ranging between 0.1 and 0.25 ppm. Values above this require that the system be checked for contamination from leakage and/or that the internal treatment and blowdown parameters be altered.[78] Undesirable boiler water impurities include dissolved mineral matter, dissolved gases, alkalinity, and acidity. The ABMA recommends that boiler water alkalinity should be less than 20 percent of the total solids content.[78] Excessive concentrations of these contaminants and characteristics cause scale, corrosion, carryover, and caustic embrittlement.

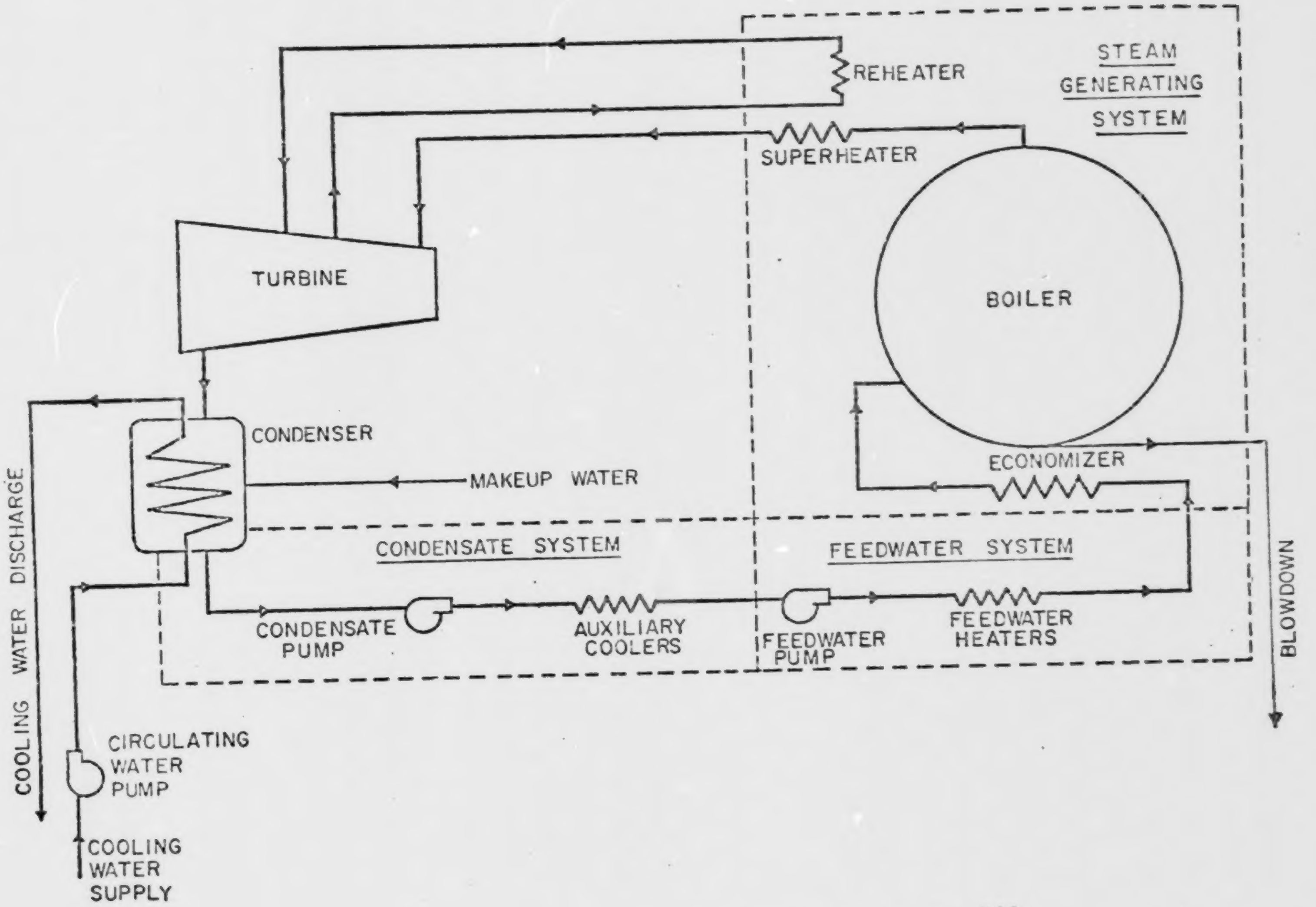
STEAM
GENERATING
SYSTEM
REHEATER
SUPERHEATER
BOILER
TURBINE
ECONOMIZER
CONDENSER
MAKEUP WATER
CONDENSATE SYSTEM
FEEDWATER SYSTEM
CONDENSATE PUMP
AUXILIARY COOLERS
FEEDWATER PUMP
FEEDWATER HEATERS
BLOWDOWN
COOLING WATER DISCHARGE
CIRCULATING WATER PUMP
COOLING WATER SUPPLY

Figure 25. Typical steam-electric plant boiler water cycle[136]

Feedwater dissolved oxygen and pH should also be monitored to prevent corrosion and boiler damage, and coupled to hydrazine and ammonia pumps to allow for instantaneous feedback and correction of hazardous situations.[78]

Associated Objectional Effects and Control Methods - Boiler water contaminants can seriously impair boiler efficiency and result in costly repair and maintenance problems due to scale formation, corrosion, carryover and caustic embrittlement. These effects and methods of control are described below.

Scale - The presence of scale on tube surfaces reduces heat transfer. As temperature rises, the solubility of many mineral constituents in the feedwater decreases. The solids precipitate in crystalline form and firmly bind to metallic surfaces. The heat transferred through surfaces covered with 0.10 to 0.20 inches of scale is reduced by 1 to 3 percent.[152] This decrease in efficiency significantly increases fuel consumption and may disturb the operating characteristics of other portions of the system. Thin scale coatings in the high heat zones, including water wall and first-pass tubes, cause overheating and subsequent rupture. Scale formation is prevented by external pretreatment, internal treatment, and blowdown. External pretreatment includes clarification, softening, ion exchange, and filtration. The objective of each of these alternatives is to reduce the concentration of salts, alkalinity and/or acidity prior to boiler feed.

Corrosion - The principal deleterious aspect of corrosion is structural failure. Extensive pitting is promoted by water containing dissolved gases such as carbon dioxide and oxygen. Low pH feedwater can cause loss of metal in wide areas while excessively alkaline feedwater causes localized embrittlement through the reaction of hydrogen and carbon. Corrosion can be eliminated by pH neutralization, deaeration, carbon dioxide neutralization, and protective film introduction. Deaeration removes oxygen by direct application of a vacuum, by heating and degasification, or by deactivation.[153] Carbon dioxide is neutralized by the addition of ammonia or suitable amines. Electron transfer and reactant diffusion can be controlled by applying inhibiting silicates or amine films.

Carryover - This term describes the passage of moisture or entrained solids from the boiler drum into the turbine. Carryover generally produces superheater malfunction and turbine blade wear. Carryover is caused by priming and foaming. Priming consists of surging water in the steam outlets caused by heightened steaming rates, load swings, ineffective mechanical steam separation, uneven fire distribution, or excessively high water level. Foaming is a result of the formation of stable, non-coalescing bubbles in the boiler water, and leads to gross entrainment of solids in the separated steam. The common causes of foaming are excessive alkalinity, excessive boiler water solids, and the presence of organics such as oil. The recommended solids concentration in boiler water in order to prevent carryover is shown below:[78]

Drum pressure, psi	Total solids, ppm	Silica, ppm
1500 - 2000	750	2
> 2000	15	1

These values are the maximum allowable so that it is advisable to operate at solids concentrations which are much lower. The saturated steam should be of the following quality:[151]

Steam contaminant	Maximum concentration, ppb
TDS	60
Sodium (Na)	20
Silica (SiO_2)	20

Carryover can be controlled by using external treatment for reducing feedwater solids concentration. These methods include clarification, filtration, softening, and demineralization. Internal alterations include reduction of water level, boiler load, and the inclusion of steam washers and mechanical steam separators. Periodic or continuous blowdown prevents solids from building up above the concentrations existing in the treated feedwater. Excessive boiler water alkalinity can be reduced by modifying the internal treatment chemicals used. A monosodium or disodium phosphate can be used in place of trisodium phosphate to reduce alkalinity.[78]

Oil should not be allowed to enter into the boiler water by leakage through pressure seals or joints, as its presence leads to severe foaming. The application of organic antifoaming agents is usually successful in controlling this problem.

Caustic embrittlement - This condition describes the presence of intercrystalline cracking in the boiler system metal. Although rare, its diagnosis requires sensitive scrutiny. Left undetected, embrittlement can lead to violent explosions. Boiler feedwater containing free hydroxide alkalinity and silica is the primary cause. If water leaks through a highly stressed joint or crevice, it will flash to steam and high concentrations of hydroxide will remain in the crack causing metal degeneration and failure. The most effective control of embrittlement is provided by insuring proper mechanical fitting. Welding and stress relieving lessen embrittlement, but existing plants with rivet jointing in drums are subject to failure. Maintenance control methods include the use of chemical inhibitors such as sodium nitrate, lignin derivatives or tannins. Boiler water alkalinity is lowered by introducing phosphate for pH control.

Boiler Feedwater Makeup Treatment - The treatment of boiler feedwater makeup is conventionally accomplished by clarification, softening, filtration, demineralization, evaporation and reverse osmosis.[137] These processes remove suspended and dissolved solids to varying extents. Figure 26 shows the general layout of a boiler feedwater treatment system.

Clarification - The sedimentation process is used to destabilize and remove suspended and colloidal solids from makeup feedwater. Coagulants, such as aluminum and iron salts or lime, are added to form precipitates. The addition of polymers or polyelectrolytes increases the rate of flocculation and sedimentation of the generated precipitants. Table 63 lists the principal coagulants used and the normal dosages.

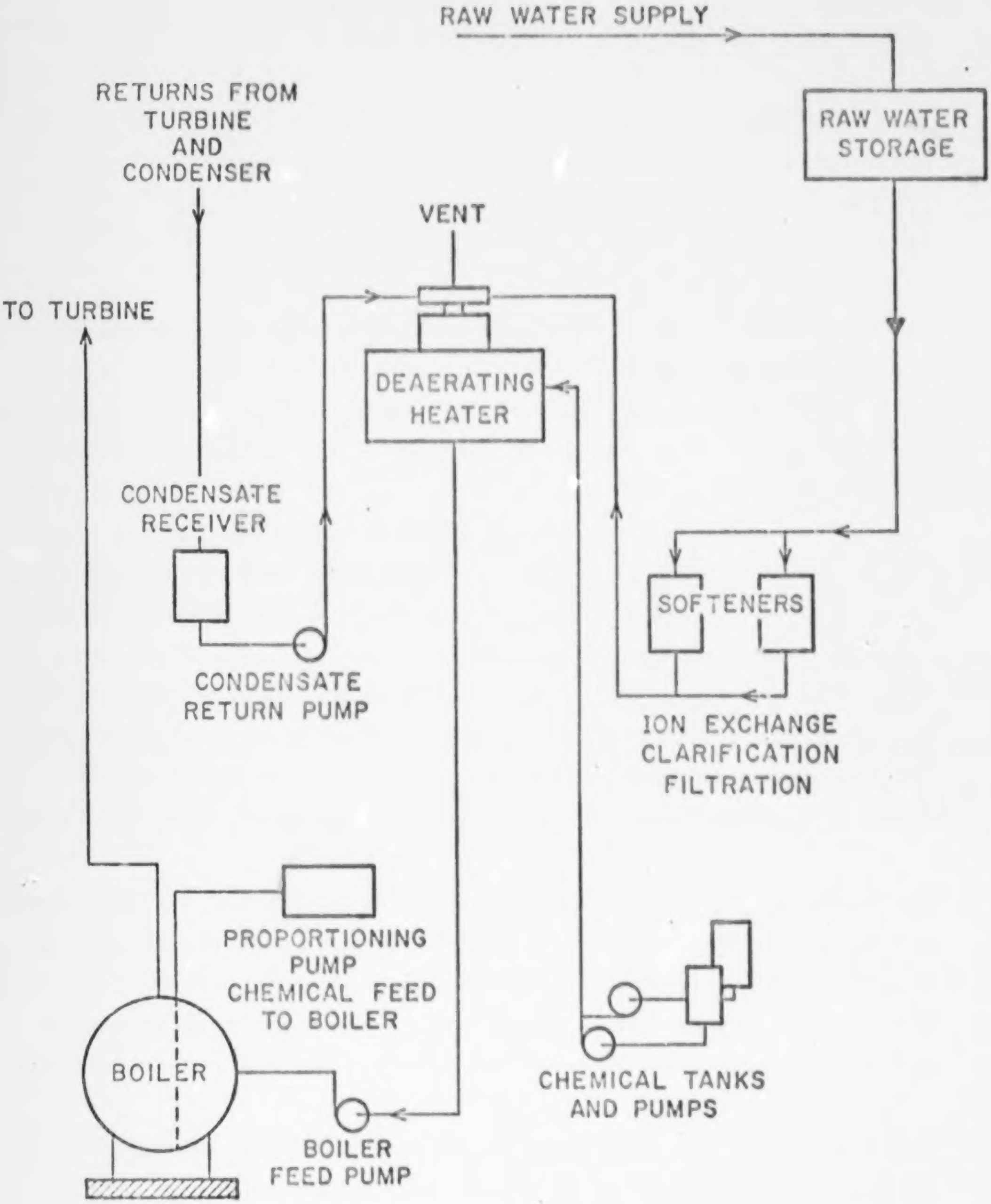
RAW WATER SUPPLY
RAW WATER STORAGE
RETURNS FROM TURBINE AND CONDENSER
VENT
TO TURBINE
DEAERATING HEATER
CONDENSATE RECEIVER
SOFTENERS
CONDENSATE RETURN PUMP
ION EXCHANGE CLARIFICATION FILTRATION
PROPORTIONING PUMP CHEMICAL FEED TO BOILER
BOILER
CHEMICAL TANKS AND PUMPS
BOILER FEED PUMP

Figure 26. General boiler feedwater treatment scheme[155]

Table 63. CHEMICAL COAGULANTS[137]

Coagulant	Purpose	Normal dosage, ppm
Alum	Main coagulant	5 - 50
Sulfate (Filter Alum)	To assist coagulation with sodium aluminate	2 - 20
Sodium Aluminate	Main coagulant	5 - 15
	To assist coagulation with aluminum sulfate	0.1 - 2
Ferrous Sulfate	Main coagulant	5 - 50
Ferric Chloride	Main coagulant	5 - 50
Calcium Carbonate (Chalk)	To assist coagulation with aluminum sulfate	-
Proprietary compounds	Main coagulant	< 2
High molecular weight compounds	Coagulant aid	0.1 - 10

Softening - Calcium and magnesium are the principal hardness-forming constituents present in boiler feedwater makeup. The lime-soda or Clark-Porter process of water softening[154] is used to precipitate these dissolved hardness-forming constituents and reduce alkalinity ($CO_3^{=}$ and HCO_3^{-}). In this process, calcium hydroxide (hydrated lime; $Ca(OH)_2$) and sodium carbonate (soda ash; Na_2CO_3) are used to precipitate Ca^{++} as $CaCO_3$ and Mg^{++} as $Mg(OH)_2$. The boiler feedwater is treated with coagulants and softeners and flows into a clarifier where solids settle and are agglomerated to form a sludge which is discharged as waste. Since the water effluent from the clarifier always contains some carryover of fine particles, boiler water clarification is generally followed by filtration.[36] Filtration can be accomplished in open gravity flow or closed pressurized tanks. The filtration media generally used include sand, stone, and anthracite coal. Various combinations of these materials are used in conventional systems to remove suspended solids and any carryover of flocculated material from clarification. Filter backwashing is performed one to three times per day depending upon the increase in head loss as the tank is operated.

Another method of softening is sodium cycle softening.[78] This is an ion exchange process which exchanges sodium for calcium and magnesium. Treated water contains the same amount of bicarbonate, sulfate, chloride, dissolved solids, and alkalinity that is in the untreated water.

Demineralization - In order to produce boiler water of quality acceptable to high pressure utility boilers, demineralization is often required. This process is capable of generating water which approaches theoretical chemical purity. The hot lime zeolite-split stream method or the mixed bed ion exchange method can be used. The split stream method requires two zeolite tanks, one containing resin in the hydrogen form and the other containing resin in the sodium form. The hydrogen resin tank replaces calcium and magnesium ions with hydrogen ions and the effluent discharged is acidic with reduced solids content. The total flow can be proportioned between both tanks in order to stabilize alkalinity at a low level and provide efficient hardness removal.

In the mixed bed method, anion and cation resins are mixed together to allow for complete simultaneous removal of electrolytes from the feedwater. When the resins become saturated with ions (breakthrough capacity) they must be regenerated. Regeneration is possible in this system because the cation resin is approximately twice as dense as the anion resin. After turbulent backwashing, the resins will settle back into separate strata. In the first stage of regeneration, small particles which have been removed from boiler water and have collected at the top of the ion exchange bed are removed by a reverse flow water wash. Backwashing usually lasts for about 10 minutes at flow rates from 5 to 7 gallons per minute per square foot of bed. In the second stage of regeneration, spent ion exchange resins are contacted with a chemical solution. Cation resins are contacted for approximately 30 minutes with a weak sulfuric acid or hydrochloric acid solution while anion resins are contacted for about 90 minutes with a weak sodium hydroxide, ammonium hydroxide, or sodium chloride solution. Spent regenerated solution contains most of the eluted ions.[36] Rinse water is then admitted to flush out any remaining eluted ions and excess regenerant solution. The volume of rinse water used is about 25 gallons per square foot of bed.[152] Wastes from resin regeneration consist primarily of soluble sodium, calcium and magnesium chlorides or sulfates,[137] plus excess sulfuric acid or alkali (NaOH) used for regeneration. A schematic diagram of the zeolite softening process is shown in Figure 27.

Evaporation - This process is capable of producing water of the same purity generated by ion exchange demineralization. Evaporation is a distillation procedure in which solids are separated from water by producing steam, after which the steam is condensed to water. The chemical composition of the waste stream is similar to that of the untreated water except that all constituents are extremely concentrated. The majority of utilities prefer the use of the ion exchange demineralization process because it is currently less costly than evaporation.

Reverse osmosis - This process is being used more extensively to prepare makeup water for power plants. Reverse osmosis requires relatively few chemicals and no regenerant wastes are produced. The process does have high power requirements and water pretreatment may be required to avoid membrane deterioration. A few pilot units in the range of 20 to 100 gpm capacity are now in operation or are being installed. The ratio of product water or permeated water to reject water varies from 1:1 to 9:1 and is dependent on the concentration and composition of the input water and the quality of the product water desired. The blowdown or reject water contains from 2 to 10 times the salt concentration of the original feed. The rejected concentrate also requires proper disposal.[137]

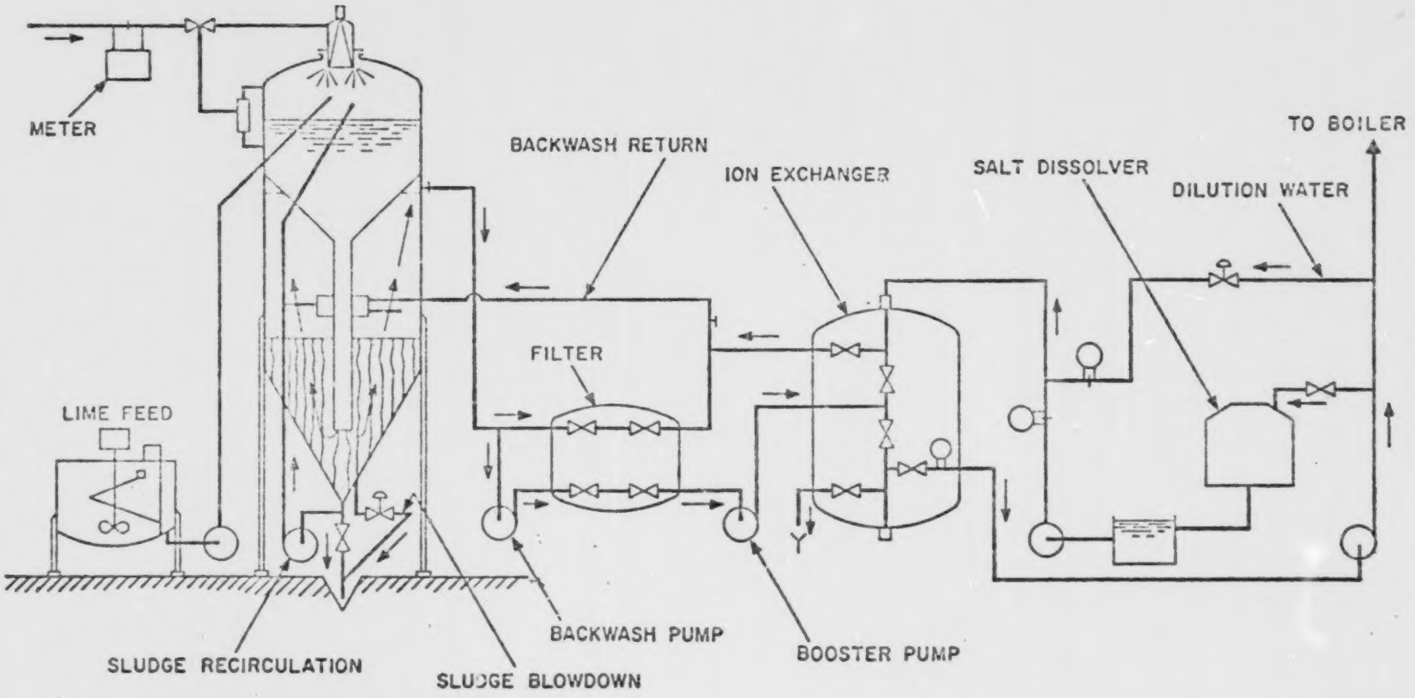
METER
LIME FEED
SLUDGE RECIRCULATION
SLUDGE BLOWDOWN
BACKWASH RETURN
FILTER
BACKWASH PUMP
ION EXCHANGER
BOOSTER PUMP
SALT DISSOLVER
DILUTION WATER
TO BOILER

Figure 27. Schematic diagram of zeolite softening process

Boiler Feedwater Makeup Treatment Wastes - Clarifier and filtration wastes are those resulting from the suspended solids in the original feedwater makeup plus a small amount of coagulants and/or softeners. Clarifier sludge can contain aluminum or iron salts derived from coagulation plus calcium carbonate and magnesium hydroxide derived from lime-soda water softening. Waste sludges from clarifiers used for domestic water treatment generally have a total solids content in the range of 3,000 to 15,000 mg/ℓ.[156] The solids concentrations of sludge withdrawn from utility boiler water clarifiers will be about the same. Approximately 75 to 80 percent of these solids are suspended, and the remainder are dissolved. Twenty to twenty-five percent of the total solids are volatile. Biochemical oxygen demand (BOD) usually runs from 30 to 100 mg/ℓ and the chemical oxygen demand (COD) ranges from 500 to 10,000 mg/ℓ.[156] The large difference between the BOD and COD values for boiler water clarifier sludge indicates the presence of considerable quantities of nonbiodegradable organics. Boiler feedwater treatment waste parameters are shown in Table 64.

Condensate Treatment - As is the case for feedwater makeup, the degree of treatment practiced in the condensate-feedwater system is directly related to the unit's operating pressure and temperature. Treatment methods are also influenced by whether the boiler is the drum or once-through type. Condenser leakage promotes the problems that condensate treatment is intended to alleviate. These problems include corrosion and scale formation caused by the introduction of oxygen, alkalinity, hard minerals, and organics such as oil.

High pressure utility boilers are capable of operating without condensate polishing systems; however, the benefits available from treating the condensate encourage the use of the process. These benefits include:[78]

- Improved turbine capacity and efficiency
- Shorter unit start-up time
- Longer intervals between boiler cleaning.

Table 64. BOILER FEEDWATER TREATMENT WASTES: ELECTRIC UTILITIES - EXTERNAL COMBUSTION

		Clarification wastes						Ion exchange wastes						Evaporator blowdown					Total volume	
1.0.00.0.0	Electric Generation	Volume, m³/day	Turbidity, JTU	TSS, mg/ℓ	Hardness, mg/ℓ	Iron, mg/ℓ	Aluminum, mg/ℓ	Volume, m³/day	TDS, mg/ℓ	Sulfate, mg/ℓ	Chloride, mg/ℓ	Sodium, mg/ℓ	Ammonia, mg/ℓ	Volume, m³/day	TSS, mg/ℓ	TDS, mg/ℓ	Sulfate, mg/ℓ	Chloride, mg/ℓ	m³/day	10⁶ gal/yr
1.1.00.0.0	External Combustion	550	1,088	25,213	3,215	352		93,910	7,408	2,065	1,708	3,112	46	66	175	730	79	194	94,526	9,113
1.1.10.0.0	Coal	316						54,000						38					54,354	5,240
1.1.11.0.0	Bituminous	306						52,350						36.5					52,693	5,080
1.1.11.1.0	Pulverized Dry	220						37,590						26.2					37,836	3,647
1.1.11.2.0	Pulverized Wet	41						7,065						4.9					7,111	685
1.1.11.3.0	Cyclone	41						7,065						4.9					7,111	685
1.1.11.4.0	All Stokers	4						610						0.5					635	61
1.1.12.0.0	Anthracite	2						300						0.5					303	29
1.1.12.1.0	Pulverized Dry	0.7						105						0.2					106	10
1.1.12.2.0	Pulverized Wet																			
1.1.12.3.0	Cyclone																			
1.1.12.4.0	All Stokers	1.3						195						0.3					197	19
1.1.13.0.0	Lignite	8						1,350						1					1,359	131
1.1.13.1.0	Pulverized Dry	4.8						810						0.6					816	78
1.1.13.2.0	Pulverized Wet	1.2						203						0.2					204	20
1.1.13.3.0	Cyclone	1.2						203						0.2					204	20
1.1.13.4.0	All Stokers	0.8						135						0.1					136	13
1.1.20.0.0	Petroleum	113						19,250						13.5					19,377	1,868
1.1.21.0.0	Residual Oil	108						18,380						12.9					18,500	1,784
1.1.21.0.1	Tangential Firing	42						7,150						5.0					7,197	694
1.1.21.0.2	All Other	66						11,230						7.9					11,304	1,090
1.1.22.0.0	Distillate Oil	5						870						0.6					874	84
1.1.22.0.1	Tangential Firing	2						318						0.2					340	33
1.1.22.0.2	All Other	3						532						0.4					535	52
1.1.30.0.0	Gas	121						20,660						14.5					20,800	2,005
1.1.30.0.1	Tangential Firing	29						5,020						3.5					5,057	487
1.1.30.0.2	All Other	92						15,640						11.0					15,743	1,518

Deaeration is accomplished in boilers of less than 1800 psi by adding sodium sulfite to the condensate. Approximately 8 ppm of sodium sulfite will remove 1 ppm of oxygen.[78] Hydrazine is used in higher pressure drum and once-through systems in place of sodium sulfite in order to prevent the formation of acidic gases. The products of the reaction between hydrazine and oxygen are volatile so that no solids are added to the boiler water and corrosive tendencies are inhibited.

The alkalinity in both once-through and drum type systems is maintained by the breakdown of hydrazine into ammonia and/or by the addition of ammonia. Condensate pH will stabilize between 8.5 and 9.5 if a residual of 0.06 ppm hydrazine is maintained at the boiler inlet.[78] This concentration of hydrazine is not adequate to completely remove all oxygen so that in high pressure boilers the emphasis must be placed on maintenance of an airtight system.

In drum type units, morpholine or cyclohexylamine are sometimes used for pH control. In low pressure drum type units, chelating agents such as ethylenediaminetetraacetic acid (EDTA) or polyphosphates such as sodium orthophosphate are used. Chelates combine with metal ions and hold them in a soluble but nonionic state. In this way, scale formation is minimized.[154] By maintaining a free residual of sodium orthophosphate, softer porous sludges of calcium and magnesium are formed instead of hard scale. Where necessary, a concentration of free caustic hydroxide may be maintained to assist in converting the magnesium salts to the less objectionable magnesium hydroxide. Periodic blowdown removes most of the sludge. The remainder can be chemically or mechanically removed.[137]

All once-through boilers employ sophisticated means for removing solids from the condensate. In many cases, deep bed or mixed bed demineralizers of high flow rates (25 to 50 gpm/sq ft) are installed directly in the condensate piping. Some plants install precoated filters for solids removal prior to demineralization despite the fact that ion exchange resin beds provide some filtration. Condensate polishing demineralizers may be designed for 30 to 50 percent of flow and are principally used only during startup and for periods in which condenser leakage occurs. In this case, treatment during normal operation may be provided by 100 percent capacity precoat filters or by the use of an ion exchange resin. The success of condensate polishing by ion exchange has prompted the installation of demineralizers in a few drum-type unit systems. As was the case for feedwater makeup treatment, the wastes produced by the regeneration of condensate demineralizers are chlorides, sulfates, and dilute solutions of sulfuric acid and caustic soda.[137] A method of condensate treatment employing ion exchange is shown in Figure 28.

Boiler Blowdown

The most comprehensive source of available boiler blowdown data is the Federal Power Commission Report FPC S-246 covering steam-electric plant and water quality data for the year 1972.[23] Approximately 55 percent of the plants generating electricity from external combustion reported boiler blowdown information. Some of the plants that reported annual volumes of boiler blowdown also reported the pH and suspended solids loading of this wastewater stream. A compilation of this FPC data is presented below.

Total annual generation of plants reporting blowdown suspended solids loadings	78,206,700 $\frac{\text{MWh}}{\text{yr}}$
Average suspended solids loading	30.8 mg/ℓ (or) ppm
pH range	5.5 - 11

Boiler blowdown refers to the periodic or continuous discharge to waste of a portion of the working fluid of a boiler to reduce the amount of dissolved and suspended solids in the boiler water. If allowed to accumulate, these solids precipitate as scale on heat transfer surfaces, limiting the effectiveness and structural integrity of these surfaces. Scale forming materials are composed of the hard salts of calcium and magnesium,

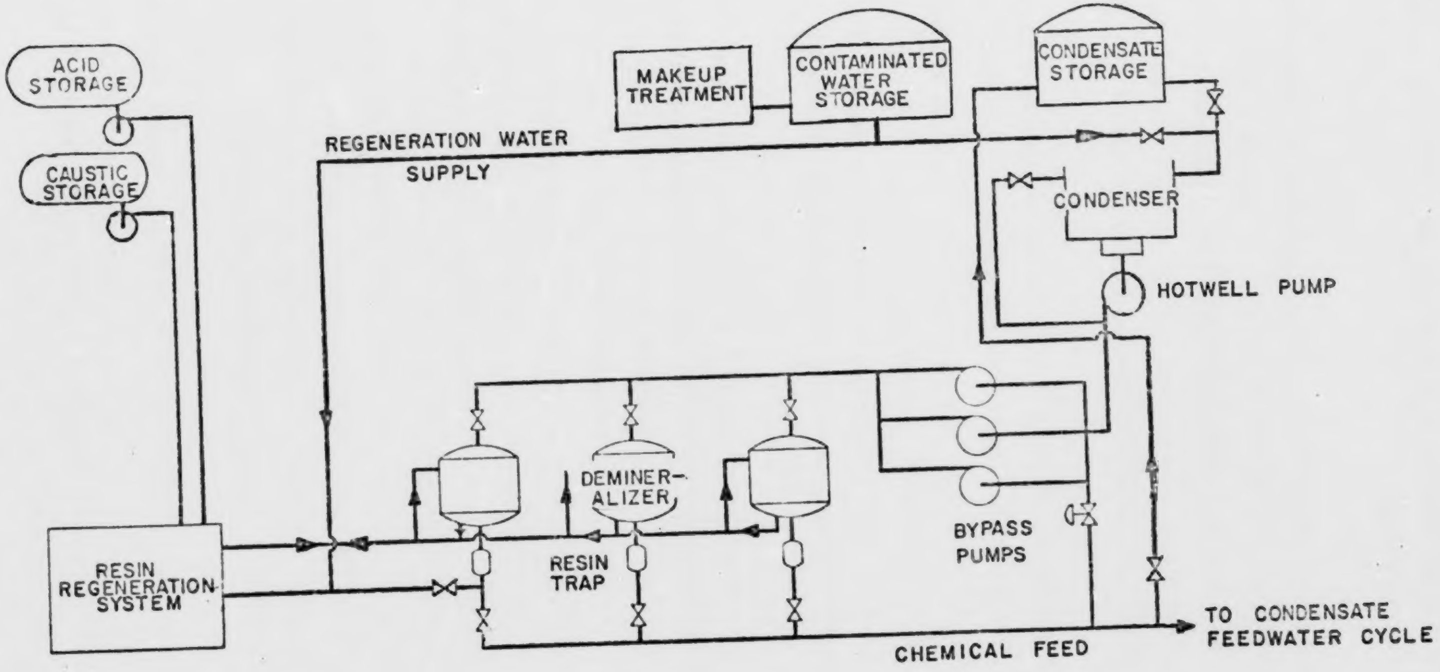
ACID STORAGE
CAUSTIC STORAGE
MAKEUP TREATMENT
CONTAMINATED WATER STORAGE
CONDENSATE STORAGE
REGENERATION WATER SUPPLY
CONDENSER
HOTWELL PUMP
DEMINER-ALIZER
RESIN TRAP
BYPASS PUMPS
RESIN REGENERATION SYSTEM
CHEMICAL FEED
TO CONDENSATE FEEDWATER CYCLE

Figure 28. Schematic diagram of condensate polishing system[13]

dissolved silicates, and to a lesser extent, iron and copper salts resulting from corrosion.

Feedwater is always treated to reduce hardness and dissolved solid and gas concentrations to low levels before it enters a boiler. In addition, ion exchange columns are used in newer installations to continuously purify the condensate. Chelating agents and pH control chemicals are added to feedwater to inhibit precipitation of scale and corrosion.

Dissolved and suspended solids nevertheless accumulate in the boiler water necessitating periodic or continuous blowdown. The fraction of boiler water discarded by blowdown ranges from near zero in nuclear and supercritical boilers with condensate polishing, to about 8 pounds per 1000 pounds of steam generated[78] in older medium pressure boilers. The frequency and volume of blowdown is not normally influenced by the type of fuel used.

Control Methods - External chemical pretreatment methods for limiting the quantity of scale forming minerals and salts are described in the feedwater treatment section. Procedures include the use of clarification, softening, ion exchange, evaporation, and reverse osmosis. The general objective of the first three processes is to substitute soluble ions for scale forming ions. Sodium phosphates and various sulfates are used to precipitate a nonadhering carbonate sludge. Chelating agents are used to complex calcium, magnesium, iron, and copper. Evaporation of feedwater, followed by condensation, generates product water with greatly reduced salt concentration. Reverse osmosis utilizes an ion permeable membrane and external pressure to transfer ions against the normal concentration gradient and produce salt-free feedwater.

Mechanical and chemical deaeration are used to remove corrosive gases and control corrosion. Sodium sulfite and hydrazine are used to chemically scavenge dissolved oxygen. Carbon dioxide is neutralized by adding ammonia or neutralizing amines.

Characteristics of Blowdown Wastes - Pollutants discharged in boiler blowdown waste water include suspended and dissolved solids, hardness, acidity, alkalinity, and phosphates. Table 65 presents concentration values which are average values for 66 percent of the nation's coal-fired power plants.

Boiler systems using hydrazine and phosphate discharge blowdown water with a pH ranging between 9.5 and 11. High pressure boiler blowdown has a total dissolved solids content in the range of 10 to 100 mg/ℓ. Blowdown from boilers using phosphate additives contains 5 to 50 mg/ℓ phosphate and 10 to 100 mg/ℓ hydroxide alkalinity. Blowdown from boilers using hydrazine contains 0 to 2 mg/ℓ ammonia.[78]

Equipment Cleaning Wastes

Tables 66 and 67 summarize wastewater volume and constituents found in equipment cleaning discharge waters. The effluent guideline document for steam-electric power generating facilities[36] reports national average figures for total suspended solids (TSS), iron, and copper, and defines the entire spectrum of waste characteristics existing in six separate plants. The ratio of national TSS to the average TSS for the six plants was used to extrapolate values for the entire range of pollutants on a national basis. Table 67 reports these extrapolated figures and the national average values for TSS, iron, and copper. The extrapolated numbers are questionable, and detailed study of permit applications on file under the National Pollution Discharge Elimination System is required to obtain better data.

Cleaning Requirements - Chemical cleaning of the water side of boiler system components falls into two categories: preoperational and operational cleaning. A wide variety of cleaning solvents are used, including acids, alkalies, complexers and chelating agents. The water side cleaning characteristics of all steam generating plants are presented here as being independent of fuel used. Actually, metal oxide deposits will form

Table 65. BOILER BLOWDOWN VOLUME AND COMPOSITION

		Volume, 10^6 gal/yr	TSS, mg/ℓ	TDS, mg/ℓ	Ammonia, mg/ℓ	Phosphate, mg/ℓ	Alkalinity, mg/ℓ
1.0.00.0.0	Electric Generation						
1.1.00.0.0	External Combustion	6540	30.8	150	1	5-50	10-100
1.1.10.0.0	Coal	3760					
1.1.11.0.0	Bituminous	3640					
1.1.11.1.0	Pulverized Dry	2611					
1.1.11.2.0	Pulverized Wet	508					
1.1.11.3.0	Cyclone	508					
1.1.11.4.0	All Stokers	45					
1.1.12.0.0	Anthracite	20					
1.1.12.1.0	Pulverized Dry	7					
1.1.12.2.0	Pulverized Wet	0					
1.1.12.3.0	Cyclone	0					
1.1.12.4.0	All Stokers	13					
1.1.13.0.0	Lignite	100					
1.1.13.1.0	Pulverized Dry	60					
1.1.13.2.0	Pulverized Wet	15					
1.1.13.3.0	Cyclone	15					
1.1.13.4.0	All Stokers	10					
1.1.20.0.0	Petroleum	1340					
1.1.21.0.0	Residual Oil	1280					
1.1.21.0.1	Tangential Firing	498					
1.1.21.0.2	All Other	782					
1.1.22.0.0	Distillate Oil	60					
1.1.22.0.1	Tangential Firing	23					
1.1.22.0.2	All Other	37					
1.1.30.0.0	Gas	1440					
1.1.30.0.1	Tangential Firing	350					
1.1.30.0.2	All Other	1090					

Table 66. EQUIPMENT CLEANING WASTEWATER VOLUME[a]

		Volume, 10^6 gal/yr
1.0.00.0.0	Electric Generation	
1.1.00.0.0	External Combustion	2184
1.1.10.0.0	Coal	1260
1.1.11.0.0	Bituminous	1222
1.1.11.1.0	Pulverized Dry	877
1.1.11.2.0	Pulverized Wet	165
1.1.11.3.0	Cyclone	165
1.1.11.4.0	All Stokers	15
1.1.12.0.0	Anthracite	6
1.1.12.1.0	Pulverized Dry	2
1.1.12.2.0	Pulverized Wet	0
1.1.12.3.0	Cyclone	0
1.1.12.4.0	All Stokers	4
1.1.13.0.0	Lignite	32
1.1.13.1.0	Pulverized Dry	19
1.1.13.2.0	Pulverized Wet	5
1.1.13.3.0	Cyclone	5
1.1.13.4.0	All Stokers	3
1.1.20.0.0	Petroleum	442
1.1.21.0.0	Residual Oil	422
1.1.21.0.1	Tangential Firing	164
1.1.21.0.2	All Other	258
1.1.22.0.0	Distillate Oil	20
1.1.22.0.1	Tangential Firing	8
1.1.22.0.2	All Other	12
1.1.30.0.0	Gas	482
1.1.30.0.1	Tangential Firing	117
1.1.30.0.2	All Other	365

[a] Table 67 presents equipment cleaning wastewater characteristics.

Table 67. EQUIPMENT CLEANING WASTEWATER CHARACTERISTICS: ELECTRIC GENERATION - EXTERNAL COMBUSTION[36]

Wastewater characteristic	Concentration, mg/ℓ
Hardness	4,000
Total solids	(14,000)[a]
Total suspended solids	127
Total dissolved solids	(9,000)
NH_3	(10)
Ni	(105)
Zn	(40)
Na	(3,200)
NO_3	(1)
Br	(320)
Mn	(12)
SO_4	(16)
Cl	(11,000)
F	(680)
Al	(8)
Cr	(240)
Cu	380
Fe	2,100
Mg	(30)

[a] Parentheses indicate extrapolated values.

on internal heating surfaces most rapidly in oil-fired boilers where radiant heat intensity is the greatest. However, differences in cleaning frequency dictated by this fact are assumed to be negligible.

Preoperational Cleaning of Boilers - During the production of carbon steel boiler tubing, mill-scale (Fe_3O_4) of varying thickness is formed on the interior metal surface. If it is not removed before operation, portions will dislodge and leave intermittent corrosion forming patches of scale. The displaced mill-scale is likely to collect in the superheater or turbine where it can create pitting and erosion. Lubricants which are applied during manufacture also must be removed prior to startup. Oils tend to collect on nuts and bolts and grime buildup during construction.

Preoperational cleaning of the water side of drum-type and once-through boiler systems is an involved procedure. The system is initially filled with caustic soda, trisodium phosphate, emulsifying or wetting agents, and fired at low pressure. This phase continues for 6 to 12 hours with frequent blowdown. The solution is drained and rinsed from drum-type systems and displaced in once-through systems. A corrosion inhibiting acid solution (hydrochloric, hydroacetic, or citirc) is then injected in order to remove mill-scale. The solution is drained or displaced, as applicable. In drum-type boilers, an alkaline boilout is performed after the acid phase. This is done with a soda ash solution and neutralizes pockets of acid and removes hydrogen gas bubbles. In once-through systems, an alkaline wash which consists of trisodium phosphate and a wetting agent is used. The final step requires provision of a passive molecular film on clean surfaces to prevent subsequent rusting. A mixture of sodium nitrite, mono and disodium phosphate is used in drum-type boilers, while hydrazine and ammonia are used in once-through boilers. The system is then cooled and prepared for service.

The wastes produced by preoperational cleaning are variable, but are most dependent upon the combination of cleaning solvents used. The waste water can be acidic or alkaline and contain oil, grease, suspended solids, phosphates, nitrates, and silica. If organic emulsifying agents are used, the effluent water may be high in BOD and COD concentration.

Operational Cleaning of Boilers - Since boiler cleaning is performed on a highly intermittent basis and because the procedure requires a degree of technical skill and specialized equipment, a cleaning contractor is often hired to carry through the cleaning operation. Usually, the utility will provide the necessary water and a means for containment of generated waste water. The cleaning organization provides tank trucks for mixing of the cleaning solvent and necessary equipment such as pumps and auxiliary piping and valves.

After a boiler is placed in service, a variety of solid constituents enter the system along with the feedwater. Some percentage of insoluble compounds will deposit on metal surfaces in spite of external feedwater treatment and boiler water blowdown. The problem is most critical in high pressure units and eventually all systems require shutdown and chemical cleaning. A study conducted by Burns & Roe, Inc.[36] indicates that cleaning frequency varies from once in 7 months to once in 100 months and that the mean time between cleanings is 30 months. Boiler scale contains precipitated salts and corrosion products. Its composition is variable and depends on the materials of construction, the composition of the feedwater, boiler chemical additives, and contaminants from infiltration. Boiler scale can consist of the following compounds:

- Calcium carbonate, sulfate, phosphate, silicate
- Magnesium phosphate, silicate, hydroxide
- Silica
- Oxides of iron, copper
- Zinc, nickel, aluminum
- Mud, silt, dirt (from condenser leakage)

As scale builds up on tube inner surfaces, the temperature loss through the tube increases and causes the steel to lose strength under particularly adverse conditions. Ultimately, the steel will plastically deform (creep) and then rupture.

The solvent used for cleaning depends upon the nature and composition of the scale, and the type of surface being cleaned. Inhibited hydrochloric acid is the solvent most widely used because of its effectiveness in removing practically all scale deposits in a rapid period of time and because of its low cost. Other acid and alkali cleaning solvents that are used include the following:

Acids	Alkalis
Sulfuric	Free ammonia
Sulfamic	Ammonium hydroxide, bifluoride
Phosphoric	Ammonium sulfate, carbonate
Nitric	Potassium bromate, chlorate
Citric	Sodium bromate, chlorate
Formic	Nitrates, nitrites
Hydroacetic	Caustic soda
Hydrofluoric	Hydrazine
	Ammonium and sodium EDTA
	Thiourea

The alkalis are used where circumstances prevent the use of a strong acid. These applications include the cleaning of stainless steel and cleaning of nonventable, nondrainable sections under circulating conditions. High velocities are used when circulating hydrochloric acid which might cause large patches of scale to detach and clog inaccessible regions. Therefore, the use of a weaker solvent which must be circulated at lower velocities in order to be effective can be justified economically.

One-stage cleaning can be used for copper and metal removal and two-stage cleaning programs can be used when copper predominates in the scale. In the first case, thiourea or some other metal complexer is used. In the latter case the first stage cleaning uses a mixture of ammonium carbonate, ammonium hydroxide, and sodium bromate. After firing and rinsing, a solution of hydrochloric acid, corrosion inhibitor, and copper complexer is fed into the system. This is followed by rinsing and alkaline flushing or boilout.

Boiler volumes range from 5,000 to 100,000 gallons. Because the cleaning operation may require a total of two to seven boiler volumes,[137] the range of discharge is extremely variable. The type of residual wastes discharged during operational cleaning depend upon the chemical solvents used. Waste water from alkaline cleaning will contain excess alkalinity, ammonium ion, oxidizing agents, phosphates, COD, and iron, copper, and hardness derived from metallic scale. These same pollutants are discharged when alkaline chelating and passivating solutions are used for rinsing after acid cleaning. The principal pollutants discharged during acid cleaning include excess acidity, phosphates, fluorides, COD, copper, iron, hardness, and turbidity. When organic solvents and other specialized cleaning solutions are used, a variety of pollutants are discharged in the rinse water. In general, the waste contains alkalinity or acidity, organic compounds, ammonium compounds, phosphates, and scale compounds.

Disposal of Boiler Cleaning Wastes - Methods of disposal of chemical cleaning boiler waste vary widely and reflect the necessity to deal with cleaning waste waters on an extremely intermittent basis. One disposal method is controlled waste release to a waterway. The waste water is neutralized and diluted in the ambient water to the extent of 5,000 or 10,000 to 1. This practice will be curtailed in the future in light of current interim guidelines and standards for steam-electric power generating plants.[130] Future use of this disposal scheme will require the attainment of discharge permits as outlined in the Water Pollution Control Act Amendments of 1972.[138]

Sedimentation and neutralization in collecting basins prior to ambient water discharge is an alternative procedure. The use of additional chemicals is minimized if alkaline and acidic waste streams are allowed to mix and neutralize in a controlled volume. Sedimentation will remove a major portion of the suspended and dissolved solids prior to discharge.

Discharge of waste to lagoons for permanent storage is another treatment method. The percentage of solids will increase as settling proceeds and supernatant water evaporates. Permanent storage basins are designed to prevent leaching of waste water to ground water. Organic air emissions from stabilization lagoons have not been previously studied but are assumed to be of negligible importance. Organic solvents are used only to a slight extent because of limited application and high cost. In addition, most organic solvents are employed by outside cleaning contractors who sometimes make provision for hauling cleaning wastes to acceptable disposal sites.

Other methods include off-site disposal, waste solvent solidification and incineration. Off-site disposal is utilized where transmission costs and effluent guidelines are not prohibitive. This includes trucking to commercial disposal sites or barging to deep ocean dumping areas. Waste solvent solidification is currently being used on an experimental basis. An outside vendor is generally contracted to provide this service. The contractor maintains the necessary equipment and the waste is prepared for disposal to landfill or abandoned mine. Incineration of waste solvents is practiced on a very limited basis. When organic solvents are used, the spent liquid is sprayed into a furnace at a rate of 50 to 100 gpm. The associated air pollution effects have proven to be minimal.[137]

The disposal method used depends upon type of waste, treatment efficiency, and cost. In the future, the point source effluent limitations developed by the EPA will be an important constraint.

Miscellaneous Cleaning Requirements and Associated Waste Water -

Condenser cleaning and wastes - Preoperational cleaning of the steam side of the condensers is done with alkaline solutions. Operational cleaning of the steam side of the condenser depends on boiler water quality and is infrequent. The water side of the condenser is usually cleaned with inhibited hydrochloric acid. This procedure must be properly controlled in order to prevent damage to stainless steel condenser tubes. The wastes produced are the same as those generated in boiler cleaning.

Feedwater heater cleaning and wastes - Preoperational cleaning with trisodium phosphates and wetting agents removes oils, grease, and preservatives from both sides of the feedwater heaters. Acid cleaners are sometimes used on the water side of the heaters but not on the steam side. This precaution is taken in order to prevent acid from remaining in the more pronounced crevices on the tube exterior. Operational cleaning of ferrous alloy tubes is generally not required. Operational cleaning of copper alloy tubing uses a 5 to 20 percent solution of hydrochloric acid, a neutralizing solution of 0.5 to 1.0 percent soda ash or caustic soda, and a final rinse with demineralized water. Cleaning can be performed during boiler cleaning. Wastes include acidity and alkalinity from separate cleaning stages. Oil, phosphates, and iron and copper ions will also be generated.

Fireside boiler and air preheater cleaning and wastes - The fireside of boiler tubes and air preheaters collect fly ash, soot, corrosion products, and airborne dust. Both must be cleaned in order to maintain adequate heat transfer rates. Cleaning is accomplished by steam soot blowing during operation or with high pressure fire hoses while the equipment is hot. Alkaline solutions may be added as cleaning aids. The frequency and quantity of fireside cleaning discharge are fuel dependent but have not been delineated by fuel because the water volume is insignificant. The acidity of cleaning wastes depends upon the sulfur content of the fuel. If the rinse is neutralized with soda ash, phosphates, or detergents, the waste may become alkaline. Other waste products include fly ash, soot, rust, magnesium salts, copper, iron, nickel, and chromium. In oil-fired boilers, the vanadium content of this waste stream may be high.

Small equipment cleaning and wastes - Other plant components, such as condensate coolers, air compressor coolers, and stator oil coolers are chemically cleaned at infrequent intervals. The common cleaning solution is inhibited hydrochloric acid with detergents and wetting agents occasionally added. This operation produces a low volume waste stream which contains variable pH, metals, oil, and suspended and dissolved solids.

Stack cleaning and wastes - Fly ash and soot deposits in stack interiors are usually cleaned with high pressure water. The waste stream from this operation contains suspended solids, high and low pH, metallic salts, and oil.

Cooling tower basin cleaning and wastes - Carbonates, microbial growth, sulfites, and windblown debris accumulate in cooling tower basins. Therefore, the cooling basin is periodically cleaned with water which results in the discharge of high quantities of suspended solids.

FUEL STORAGE AND HANDLING EMISSIONS

Coal Storage Requirements

In order to insure continuous operation, coal-fired generating plants maintain a 75- to 90-day coal supply on site. Table 68 shows coal storage requirements based on the average of data supplied in EPA's Effluent Limitations Guideline Document.[36] These estimates are based on a storage requirement of 15 to 75 acres per 1000 MW of generating capacity. The reported fivefold range is due to variation in coal storage practices and land area availability. Other estimates indicate that an area of 40 acres is required for a 3,000 MW generating plant.[115] In addition, a private power company indicated that the government estimates may be low by a factor of 6 for specific plants.[157] Other projections indicate 1/2 to 1-1/2 acre feet are required for each MW of rated capacity in storage piles ranging from 25 to 40 feet high.[137] A height of 30 feet and a volume of 1.2 acre feet/MW, corresponding to an area of 40 acres for a 1,000 MW plant, were used in compiling Table 68.

Coal Pile Drainage

Surface run-off from natural precipitation constitutes the primary source of potential contamination of surface waters due to coal storage. An

Table 68. ELECTRIC UTILITY: FUEL STORAGE AND HANDLING EMISSIONS, 1974

		Coal storage requirement			Coal pile drainage[a]	Particulate air emissions, tons/yr
		Weight, tons	Area, acres	Volume, acre feet	Volume, 10^6 gal/yr	
1.0.00.0.0	Electric Generation	93,000,000	7,700	230,000	7,900	170
1.1.00.0.0	External Combustion	93,000,000	7,700	230,000	7,900	170
1.1.10.0.0	Coal	93,000,000	7,700	230,000	7,900	170
1.1.11.0.0	Bituminous	90,000,000	7,500	225,000	7,700	160
1.1.11.1.0	Pulverized Dry	64,500,000	5,300	160,000	5,600	115
1.1.11.2.0	Pulverized Wet	12,000,000	1,000	30,000	1,050	21
1.1.11.3.0	Cyclone	12,000,000	1,000	30,000	1,050	21
1.1.11.4.0	All Stokers	1,500,000	200	5,000	100	3
1.1.12.0.0	Anthracite	500,000	35	1,050	40	1
1.1.12.1.0	Pulverized Dry	175,000	12	370	14	0.3
1.1.12.2.0	Pulverized Wet	0	0	0	0	0
1.1.12.3.0	Cyclone	0	0	0	0	0
1.1.12.4.0	All Stokers	325,000	23	680	26	0.7
1.1.13.0.0	Lignite	2,500,000	165	4,950	160	4
1.1.13.1.0	Pulverized Dry	1,500,000	100	2,950	100	2.2
1.1.13.2.0	Pulverized Wet	37,500	25	750	22	0.75
1.1.13.3.0	Cyclone	37,500	25	750	22	0.75
1.1.13.4.0	All Stokers	25,000	15	500	16	0.3
1.1.20.0.0	Petroleum	NA	NA	NA	NA	NA
1.1.21.0.0	Residual Oil					
1.1.21.0.1	Tangential Firing					
1.1.21.0.2	All Other					
1.1.22.0.0	Distillate Oil					
1.1.22.0.1	Tangential Firing					
1.1.22.0.2	All Other					
1.1.30.0.0	Gas	NA	NA	NA	NA	NA
1.1.30.0.1	Tangential Firing					
1.1.30.0.2	All Other					

[a] The reported coal pile drainage properties (see Table 69) apply to all coals.

Note: NA - Not Applicable.

impervious clay foundation is generally provided for coal storage areas to prevent ground water contamination.[137]

Table 25 presented the yearly volume of coal pile drainage from electric utilities, the pollutant components, and a summary of hazardous effects. The national coal pile drainage volume is reported to be approximately 7.9×10^9 gallons (30×10^6 m^3) per year, based on average rainfall rates.[36,137] The pollution potential of the coal pile runoff depends upon meteorological conditions, pile area, and type of coal used. Coal runoff usually has a low pH and a high concentration of dissolved solids including iron, magnesium, and sulfate. Aluminum, sodium, manganese, and other metals may also be present in undesirable amounts. Given the yearly runoff volume for all coal shown in Table 68, a concentration of 1 mg/ℓ is equivalent to a total emission of 65,000 lb/yr of any particular constituent.

Coal pile drainage contains dissolved metallic salts in the concentration range shown in Table 69. The variability of drainage composition reflects the variety of coals used as well as the history and rate of rainfall. During heavy rainfall the level of dissolved solids emitted will be high initially and will rapidly decrease. When rainfall is light, the long retention time may allow more diffusion, and hence more chemical reaction to occur and result in higher pollutant concentrations. The values provided in Table 69 are based on data included in information filed under the National Pollution Discharge Elimination System (NPDES),[150] as reported in an EPA guideline development document.[36] Data presented are based on a survey of 66 percent of the major steam-electric power plants. Additional information can be obtained by a more detailed survey of the NPDES files.

Seepage to ground water can be minimized by storing the coal on an impervious base of clay or plastic liners. Installation of a simple drainage system for holding and treatment can eliminate surface water contamination for normal quantities of precipitation. Examples of specific treatment

Table 69. COMPOSITION OF DRAINAGE FROM COAL PILES[36]

	Concentration, mg/ℓ[a]
Alkalinity	15 - 80
BOD	3 - 10
COD	100 - 1,000
Total solids	1,500 - 45,000
Total suspended solids	20 - 3,300
Total dissolved solids	700 - 44,000
Ammonia	0.4 - 1.8
Nitrate	0.3 - 2.3
Phosphorus	0.2 - 1.2
Turbidity	6 - 505
Acidity	10 - 27,800
Total hardness	130 - 1,850
Sulfate	130 - 20,000
Chloride	20 - 480
Aluminum	825 - 1,200
Chromium	0 - 16
Copper	1.6 - 3.9
Iron	0.4 - 2.0
Magnesium	90 - 180
Sodium	160 - 1,260
pH	2.2 - 8.0

[a] Appropriate for all values except pH. Using the volumes in Table 68, 1 mg/ℓ is equivalent to 65,000 lb/yr.

schemes are neutralization and sedimentation. These processes first require the collection and discharge of runoff to waste settling basins. Neutralization can be accomplished by adding lime, soda ash, or an alkaline waste stream from another process. Solids sedimentation can be achieved by providing extended retention time, and it can be accelerated with the addition of coagulants.

Drainage collection systems and treatment capacities should be designed to receive water quantities that contain the maximum pollutant concentrations. Since the waste concentrations produced by heavy rainfalls are not critical, something less than maximum storm flow should be used as the basis of design. Therefore, the current design rule is to provide capacity adequate for 1 inch of rainfall over the storage area during a 24-hour period.[137]

Air Emissions

Coal Preparation - The preparation of coal prior to delivery to the power plant facility can involve several operations: cleaning, demoisturizing, dedusting, sizing, etc. The processing and storage of coal at the power plant also require extensive handling and size reduction equipment. The size reduction equipment is usually well controlled and not a major source of emissions.

The size of coal delivered to the plant will depend upon the boiler type. For stoker-fired units it is customary to supply coal of the proper size and no on-site crushing or sizing is required. Pulverized and cyclone furnaces both require crushing equipment and fine pulverizers are required for pulverized-fired furnaces. Generally, these latter furnace types can accommodate any size of coal available. Coal sizes are not well standardized because of the differences in fracturing characteristics of the various coals. Bituminous coal size can vary from run of mine coal (8 inches or larger) to coal which passes through a 3/4-inch round screen.

Stoker coal, which will vary with stoker type, generally is passed by a 1-1/4 inch but retained on a 3/4 inch screen.

Coal Storage - Data on air emissions from coal storage are extremely scarce. The discussion here is based on information supplied by the Monsanto Research Corporation.[158] Atmospheric emissions of fugitive dust, carbon monoxide, and gaseous hydrocarbons evolve from coal storage piles. At a distance of 50 meters from a coal pile, the concentrations of carbon monoxide and hydrocarbons are well below the ambient air quality standards. No POM emissions were detected. Particulate matter in the form of coal dust is the most important air emission from coal storage piles.

Particulate emissions are influenced by wind speed, pile surface area, coal density, and the prevailing precipitation - evaporation index. The dust emission factor from coal piles has been estimated to be equal to 0.59 mg/kg-yr (0.00118 lb/ton-yr).[158] This is equivalent to 1.1×10^5 lb/yr of coal dust emission based upon 93,000,000 tons of coal stored per year. Wind erosion reportedly represents only one-third of total emissions from aggregate storage piles with the remainder attributed to various transport and handling operations.[159] In accordance with this information, a factor of 3 has been applied to the above estimate of wind erosion loss to estimate total particulate air emissions from coal storage and handling.

Storage of Oil and Natural Gas - Emissions from the delivery, storage, and transfer of petroleum and natural gas are negligible for the electric utility industry. The only pollutants emitted from petroleum and natural gas handling operations are hydrocarbons.

FLUE GAS DESULFURIZATION

Sludge Composition and Emissions

The data presented in Table 70 are for an expected application of flue gas desulfurization to 7,000 MW of capacity in 1975.[160] The composition data presented in the table are based on the use of limestone scrubbing solely. These values are based on the use of coal containing 3.5 percent sulfur and 10 percent ash. Although limestone scrubbing is presently the most widely used scrubbing method, there is some advantage to using lime, particularly for high sulfur content fuels.[61] The use of limestone instead of lime will increase the solid waste generated by about 25 percent.

Reference 160 was used to determine the area requirements and the application of disposal methods. Area requirements are a direct function of the sulfur content of the fuel burned. Ash content must also be considered if particulates and SO_2 are collected in a common scrubber or if they are collected separately and combined in a common waste stream or pond. The estimates are based on the application of scrubbers to only coal-fired utility units. Flue gas desulfurization has been and will be applied to oil-fired units, particularly those burning high sulfur content oil.[161]

There is no information available concerning air emissions from landfill. Similarly, there is very little information concerning water pollution from leaching and/or runoff from ponds and landfill. These environmental considerations will be discussed below for the lime/limestone scrubbing systems followed by a brief discussion of alternative flue gas scrubbing processes.

Fly ash may be removed in the scrubber or in a control device upstream of the SO_2 control scrubber. Although both alternatives are being utilized, it is imperative for many processes other than lime/limestone scrubbing that fly ash removal is carried out prior to the SO_2 removal process. Usually, however, the fly ash removed is combined with the sludge in a single disposal system.

Table 70. EFFLUENTS FROM LIMESTONE SCRUBBERS[a]

Weight	9,000,000 tons/year	
Composition		
$CaCO_3 \cdot 1/2\ H_2O$	2,135,000 tons/year	
$CaSO_4 \cdot 2\ H_2O$	315,000 tons/year	
$CaCO_3$	1,190,000 tons/year	
SO_2 removed	670,000 tons/year	
Fly ash	2,016,000 tons/year	
Disposal method		
Ponding	110 acres/year	2750 acre-feet
Landfill	15 acres/year	375 acre-feet
Landfill and fixation	5 acres/year	125 acre-feet
Air emissions from landfill	4,500 tons/year	

[a] Assuming application of flue gas desulfurization to 7,000 MW of capacity in 1975.

Disposal Methods

The disposal methods were based on information provided in references 160 and 162, with area requirements based on storage to a 25-foot depth. Disregarding the many technical difficulties that have been encountered in the development of lime/limestone and other scrubbing systems, one of the most troublesome problems associated with lime/limestone processes is the difficulty of sludge disposal. If EPA estimates of about 70,000 MW of flue gas desulfurization capacity operating in 1985[165] are correct, a total of 100,000,000 tons per year of sludge and ash would be produced (50 percent solids basis). Scheduled and predicted capacity are affected by a shortage of hardware vendors, the lead times required for design and construction, and a reluctance on the part of power companies to undertake the high capital investment required.

The following qualitative comparison between scrubber sludge and fly ash, as presented in reference 61, will be helpful in the assessment of water and solid waste disposal problems associated with these materials:

- The sludges typically contain calcium sulfite, calcium sulfate, calcium carbonate and fly ash in varying compositions. Fly ashes typically contain silica, alumina and hematite. The compounds in the scrubber sludge are more soluble than those in the fly ash.
- The high sulfur content of the sludge creates an additional problem of sulfur removal for manufacturing processes requiring high temperatures.
- Both sludge solids and ash will contain trace elements and other species originating in the coal, lime/limestone or water. The primary source of trace metals is the coal (ash).
- Sludge and ash liquors will both contain dissolved species. Untreated sludge liquors normally have a lower pH than fly ash liquors, hence trace metal solubility is generally greater.
- Sludge liquors may contain significant quantities of chlorides.
- Untreated sludge settles to about 50 percent solids, and will require more storage volume per unit weight than ash which settles to about 80 percent.

At this time disposal of scrubber sludges by ponding and landfill appears to be the only important near term alternative. Although water pollution potential appears high, there appear to be minimal problems for a lined and well-engineered pond.[164] However, if the pond is operated in an open loop mode to minimize some of the technical problems associated with the chemistry of the scrubbing process, serious water pollution problems may result from runoff of the bleed stream. Closed loop operation will probably be required, provided scrubbing systems can be operated in this mode. The composition of pond liquor from a closed loop system estimated for TVA's Widow Creek Operation is given in Table 71.

Table 71. COMPOSITION OF POND LIQUOR (CLOSED LOOP OPERATION)[165]

Constituent	Concentration, mg/ℓ
Calcium	830
Magnesium	230
Sulfate	1400
Sulfite	145
Chloride	1200
Sodium plus potassium	50
Iron	0.07
Barium	0.2
Cyanide	< 0.01
Zinc	0.02
Mercury	< 0.0002
Nickel	< 0.05
Copper	0.03
Chromium	0.11
Cadmium	0.001
Phosphate	0.1
Total dissolved solids	5700

The concentration of toxic trace elements in the clarifier underflow from open loop systems is given in Table 72. Based on data from sludge liquors analyzed thus far, the following pollutants have appeared substantially in excess of water quality criteria and therefore are of concern: mercury, selenium, boron, chloride, sulfate, and total dissolved solids.

If landfilling is used, chemical fixation has been suggested as a means of eliminating water pollution problems due to leachates. Fixation methods have been developed by at least three companies (Chemfix, Dravo, and IUCS). The Chemfix fixation process involves the reaction of at least two chemical components to form chemically and mechanically stable solids. The chemicals react with all polyvalent metal ions to produce stable, insoluble, inorganic compounds, which should reduce leachate trace elements as shown in Table 73.

Table 72. SUMMARY OF TCA LIMESTONE SLUDGE LIQUOR METAL ANALYSIS[164] (OPEN LOOP OPERATION), TVA SHAWNEE POWER STATION

Element	Clarifier underflow liquor, ppm[a]
Arsenic (As)	0.2[b]
Beryllium (Be)	0.01
Cadmium (Cd)	0.005
Calcium (Ca)	2500[c]
Total chromium (Cr)	0.05
Copper (Cu)	0.05
Lead (Pb)	0.1[b]
Magnesium (Mg)	600[c]
Mercury (Hg)	0.06[d]
Selenium (Se)	0.3[b]
Zinc (Zn)	0.5

[a] Equivalent to mg/ℓ.

[b] Exceeds USPHS Standards - 1962.

[c] Total dissolved solids exceed USPHS Standards - 1962.

[d] Exceeds some state standards.

Table 73. COMPARISON OF TRACE ELEMENTS ANALYSES BETWEEN RAW SLUDGE AND LEACHATE FROM THIS SLUDGE AFTER CHEMICAL CONDITIONING BY FIXATION

Constituents	TVA Shawnee TCA limestone raw sludge, ppm	Leachate water from conditioned sludge, ppm
Arsenic (As)	2.2	< 0.10
Cadmium (Cd)	0.30	< 0.10
Chlorides (Cl^-)	2,000	64
Total chromium (Cr)	2.8	< 0.25
Copper (Cu)	1.5	< 0.10
Iron (Fe)	120	< 0.10
Lead (Pb)	26	< 0.10
Mercury (Hg)	< 0.10	< 0.10
Nickel (Ni)	3.5	< 0.10
Zinc (Zn)	16	< 0.10
Phenol (C_6H_5OH)	< 0.25	< 0.10
Cyanide (CN^-)	< 0.10	< 0.10
Sulfate (SO_4^-)	> 10,000	400

The Dravo fixation process chemically fixes the sludge by the addition of "Calcilox." The Calcilox is added to the sludge during pumping to a disposal basin. The solids fraction settles and cures over a 30-day period. The solids can then be removed to the final disposal site, or the entire process can be carried out at the final site. The conditioned sludge has clay-like properties and can be used as landfill.[164] Dravo has received a permit for an installation at Ohio Edison's South Mansfield Plant.

The IUCS fixation process uses fly ash and a lime additive to chemically fix the sludge. The quantity used depends upon the reactivity of the fly ash and the water content of the sludge. The material produced by this process can develop strengths of 300 psi in 7 days and over 1,000 psi after 1 month. Because of the decreased permeability and the chemical fixation of the trace elements, the release of pollutants to ground waters is about 10,000 times less than that of untreated sludge.[164]

Information concerning the effectiveness of the fixation processes on leaching, ground water runoff, etc., is needed, and both Dravo and Commonwealth Edison at its Will County Station are conducting leachate tests.[61] Further studies will be conducted by Aerospace Corporation at the Shawnee test facility to resolve some of the uncertainties concerning fixation.

Utilization

Utilization of the sludge from nonregenerative processes is hampered by the physical and chemical properties of the sludge as it comes from the scrubber or disposal pond. The sludge contains considerable quantities of water which must be removed before the solids can be utilized. The solids portion also contains significant amounts of sulfur and smaller amounts of toxic trace elements which may be released to the environment. Table 73 shows some of the potentially harmful constituents of the raw sludge. The sludge may be used in the same products that utilize fly ash.

The amount of fly ash used in 1972 was approximately 8 percent of the amount produced. This figure gives some idea of the potential of sludge utilization and should probably be considered a maximum as the sludge would be competing with fly ash. The sludge also has other potential uses as shown in Table 74, but the amount used will be very small because of physical, environmental and economic limitations. The largest use of sludge will probably be as landfill, which is actually a means of disposal.

Air Emissions From Scrubbers

Removal efficiencies for SO_2 and particulates have been reported in references 164 and 165. SO_2 removal efficiencies are in the 90 percent range. Overall particulate efficiencies are in the 98 to 99 percent range.[161,166] More work remains to be done, however, on the efficiency as a function of particle size. Another important parameter yet to be reliably determined is the amount of fly ash and scrubbing liquor entrainment in the effluent particulate. The limited data available suggest that fly ash represents about 60 percent of the total and the remainder is entrainment of slurry liquor. The extent of sulfate emissions from the latter category of emissions should be determined.[167]

Other Processes for SO_2 Removal

Sulfur oxide removal technologies are classified as throwaway or regenerative processes. As discussed above in the case of lime/limestone scrubbing processes, air pollution problems may be converted to potential water or solid waste disposal problems. Regenerative processes, if they can be operated in a completely closed loop mode, eliminate water pollution and reduce solid waste problems by conversion of the SO_2 to a product which, if not saleable, is greatly reduced in volume. Table 75 depicts the area that would be required to store the disposal products of 20 years' operation of a 100,000 MW system.[168]

Table 74. POTENTIAL PRODUCT APPLICATIONS[164]

Uses same as or similar to those for fly ash	Potential new uses
Concrete admixture (structure and products)	Autoclaved products - gas concrete, bricks, mineral aggregate
Manufacture of portland cement	Hot press sintering - pipes, metal coatings
Fired brick	Gypsum products - wallboard, plaster
Filler in bituminous concrete	Mineral recovery
Road base course, parking lots, etc.	Sulfur or sulfuric acid production
Structural fill	Artificial aggregate
Soil amendment	
Mine void fill	
Neutralization of acid mine drainage	

Table 75. AREA REQUIRED FOR DISPOSAL OF ASH, SLUDGE AND PRODUCTS FROM A 100,000 MW SYSTEM - 20 YEARS' OPERATION[168]

Disposal product	Storage area required, square miles (depth - 10 feet)
Fly ash, 80% solids	46
Limestone sludge, 50% solids	160
Lime sludge, 50% solids	123
Sulfuric acid, 95%	33
Sulfur, 90% recovery	9

The advantage of conversion to sulfur or sulfuric acid is apparent from a storage viewpoint. Economic attractiveness would also be enhanced if sales value could be realized for the sulfur or sulfuric acid obtained from many regenerative processes.

The technologies for SO_2 removal are summarized in Figure 29, taken from reference 169. Summary descriptions of six processes that have gained some acceptance in the United States are provided in Table 76. The following additional processes are in the prototype stage of development on utility or industrial boilers: Thoroughbred 101 process,[170] Foster Wheeler-Bergbau Forschung process,[171] and the Shell Flue Gas Desulfurization process.[172]

The future acceptance of these systems will depend largely on successful demonstration of reliability in the 100 desulfurization units which have been installed or planned for installation by 1980 in utility plants. At the present time several plants appear to be operating at high availability as shown in Table 77, obtained from reference 173. However, the units operating with high reliability are unique with regard to their location (high water evaporation rates), coal properties (particularly low chlorine content) or the chemical composition of the reactants. The peculiarities of these systems must be evaluated with respect to other systems not operating in as successful a fashion. Other factors such as scrubber design, methods of construction, extent of saturation and oxidation are also in need of study at this time.

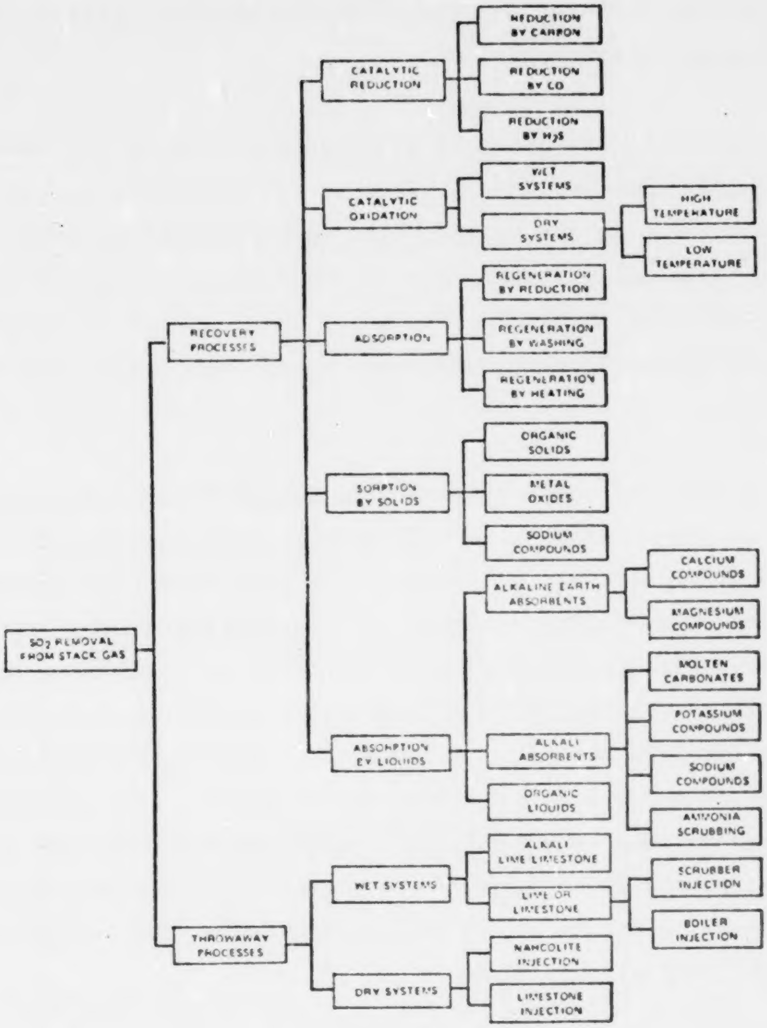
SO$_2$ REMOVAL FROM STACK GAS
RECOVERY PROCESSES
THROWAWAY PROCESSES
CATALYTIC REDUCTION
CATALYTIC OXIDATION
ADSORPTION
SORPTION BY SOLIDS
ABSORPTION BY LIQUIDS
WET SYSTEMS
DRY SYSTEMS
REDUCTION BY CARBON
REDUCTION BY CO
REDUCTION BY H$_2$S
WET SYSTEMS
DRY SYSTEMS
HIGH TEMPERATURE
LOW TEMPERATURE
REGENERATION BY REDUCTION
REGENERATION BY WASHING
REGENERATION BY HEATING
ORGANIC SOLIDS
METAL OXIDES
SODIUM COMPOUNDS
ALKALINE EARTH ABSORBENTS
CALCIUM COMPOUNDS
MAGNESIUM COMPOUNDS
MOLTEN CARBONATES
POTASSIUM COMPOUNDS
ALKALI ABSORBENTS
SODIUM COMPOUNDS
ORGANIC LIQUIDS
AMMONIA SCRUBBING
ALKALI LIME LIMESTONE
LIME OR LIMESTONE
SCRUBBER INJECTION
BOILER INJECTION
NAHCOLITE INJECTION
LIMESTONE INJECTION

Figure 29. Technologies for the removal of sulfur dioxide from stack gas (from reference 169)

Table 76. SUMMARY DESCRIPTION OF FLUE GAS DESULFURIZATION PROCESSES

Process	Classification/ operating principles	SO_2 particulate efficiency	Development status	Application	Implementation	Advantages	Disadvantages
Lime/limestone scrubbing	Throwaway process/wet absorption in scrubber by slurry; Insoluble sulfites and sulfates disposed of as waste.	Up to 90 percent SO_2 removal/99 percent fly ash removal by most scrubbers.	Most studied but reliability questionable due primarily to scaling; 16 full scale units in operation or planned for start-up by 1977.	Old but preferably new power plants; coal or oil-fired.	An additional 40-60 units forecast for installation by 1977; forecast appears optimistic; 4-5 years lead time needed for new plants; 3 years for retrofit of old plants.	Cheapest of existing processes; elimination of particulate control requirement.	Technical reliability doubtful; waste and water pollution problems; reheat of scrubber exit gases needed; supply and handling of large volumes of reactant may be problems.
Double alkali process	Throwaway process/wet absorption in scrubber; reactants and reaction products soluble; reaction products precipitated and removed from recycled reactant solution outside of scrubber; most common reactant sodium sulfite.	High efficiency > 90 percent SO_2 removal/high particulate removal as above.	Active area but no full scale demonstration as yet; G.M. installed a unit on a coal-fired boiler in Feb. 1974; several sulfate removal schemes under study.	As above with potentially lower cost and greater ease of operation favoring some inroads into smaller plants.	Research-Cottrell estimates $600 million a year market by 1979; a second generation lime/limestone system; lead times as above for power plants.	Potentially cheaper, simpler and more reliable than lime/limestone system.	Similar to above and all throwaway systems.
Magnesium oxide scrubbing	Regenerative process/wet absorption by magnesium oxide slurry; fly ash removed prior to or after scrubbing; magnesium oxide regenerated by calcining with carbon; SO_2 byproduct can be converted to sulfuric acid or sulfur.	90 percent SO_2 removal/ particulate removal as required by prescrubber.	One full scaled unit on test at Boston Edison 150 MW oil-fired unit	Similar to lime/limestone but oil-fired boilers will not require particulate control upstream of scrubber.	No known plans for immediate implementation; lead times as for lime/limestone systems.	May be more reliable than lime/limestone process; no known waste disposal problems; regeneration facility need not be located at utility.	Cost of regeneration; marketing of sulfur products; reheat.
Wellman-Lord	Regenerative process/ sodium base scrubbing with sulfite to produce bisulfite. regeneration in an evaporative crystallizer. Sulfate formed either purged or removed by selective crystallization.	>90 percent SO_2 removal particulate removal as above by prescrubber.	Reliably operated (> 9000 hours) in Japan. Full scale demonstration scheduled at Northern Indiana Public Service coal-fired 115 MW boiler; sulfate removal vital to success.	As above.	As above.	More reliable than lime/limestone system based on Japanese experience; simplicity of unit operations in regenerator; waste disposal problems reduced.	Some bleed of solution to remove undesirable reaction products a source of water pollution, otherwise as above.

Table 76 (continued). SUMMARY DESCRIPTION OF FLUE GAS DESULFURIZATION PROCESSES

Process	Classification/ operating principles	SO_2 particulate efficiency	Development status	Application	Implementation	Advantages	Disadvantages
Citrate system	Regenerative process/flue gas washed to remove particles and SO_3, cooled and absorbed in sodium citrate-citric acid solution in packed tower; solution then reacted with hydrogen sulfide to form sulfur.	> 95 percent SO_2 removal/ particulate removal as required.	New development by Bureau of Mines; Now testing 1000 cfm pilot plant; also 2000 cfm unit in Terre Haute, Indiana. High potential.	As above.	As above.	High efficiency;economic; no intermediate SO_2 regeneration; high reliability; potentially most attractive of viable processes.	Marketing of sulfur; reheat.
Catalytic oxidation	Regenerative process/ catalytic oxidation by V_2O_5 at 850-900°F to convert SO_2 to SO_3 followed by condensation to form 70-80 percent H_2SO_4. Variation of contact process applied to dilute gases.	85-90 percent SO_2 recovery/high particulate efficiency needed to avoid plugging and fouling of catalyst.	Two-year test period on 15 MW boiler; also test on 100 MW boiler of Illinois Power Company; reliability not demonstrated.	New plants, oil or coal.	As above.	Relatively simple and known technology; minimal mechanical operations; no relevant reheat requirements.	Expensive; poor quality sulfuric acid; poor reliability with appreciable downtime; extra ducting to avoid problems associated with ESP failures and high temperature gases.

Table 77. PERFORMANCE SUMMARY OF OPERATIONAL SCRUBBER UNITS

Utility	Unit (Mw)	Vendor	Process	Start-Up	SO2 Removal	Unit Cost: Capital; Operation	Availability
Ariz PS	Cholla-1 (115)	Research-Cottrell	Limestone	10/73	85%	$44/kw; 5.5 mills/kwhr	1974–91%; 1/75–98%
Boston Ed	Mystic-6 (150)	Chemico	Magnesium Oxide	4/72	90%	$25/kw; 3.9 mills/kwhr	1/74 to 6/74– 60% (test ended 6/74)
Com Ed	Will City-1 (167)	Babcock & Wilcox	Limestone	2/72	82%	$96/kw; 4.5 mills/kwhr	Module "A" 82% last 11 mos., 99% in 1/75; "B" down
Dairyland Co-op	Alma (60)	Foster-Wheeler	Lime	6/71	25%		30-day run longest; now down
Duquesne Lt	Phillips (410)	Chemico	Lime	7/73	60%	$70-$75/kw; 2.1 mills/kwhr	"Essentially" 100% in 1/75; previous record not given
General Motors	Parma (32)	Koch	Double Alkali	3/74			Being modified
Gulf Pwr	Scholz-1 (20)	ADL/Comb. Equip. Associates	Double Alkali	2/75			Startpup Feb. 5; down total of 8 hrs. first 5 days
Illinois Pwr	Wood R-4 (110)	Monsanto Enviro-Chem	Catalytic Oxidation	10/72	85%	$73/kw; 4 mills/kwhr	Longest run: 24 hours
Kansas City P&L	Hawthorn-3 (140)	Comb. Engnrg.	Limestone	11/72	70%	$19/kw; 2.5 mills/kwhr	30-40% generally; 12/74 – 16%
	Hawthorn-4 (100)	Comb. Engnrg.	Limestone	8/72	70%	$19/kw; 2.2 mills/kwhr	30-40% generally
	La Cygne (820)	Babcock & Wilcox	Limestone	6/73	72%	$43/kw	76% last 12 mos.; boiler now down for overhaul
Kansas P&L	Lawrence-4 (125)	Comb. Engnrg.	Limestone	12/68	75%		86% last 11 mos.
	Lawrence-5 (400)	Comb. Engnrg.	Limestone	11/71	65%		Boiler on gas in recent months
Key West	Key West (37)	Zurn Air Systems	Limestone	10/72	85%	$21.60/kw	Damage caused shutdown Jan. 28; Mid-March restart
Louisville G&E	Paddy's Run (65)	Comb. Engnrg.	Lime	4/73	90%	$57/kw	"Essentially" 100% since 6/74
Nevada Pwr	Gardner-1 (125)	Comb. Equip. Associates	Sodium Carbonate	12/73	85%		12/73 to 12/74 – over 90%; 1/75 – 65%
	Gardner-2 (125)	Comb. Equip. Associates	Sodium Carbonate	12/73	85%		12/73 to 12/74 – over 90%; 1/75 – 94%
Pepco	Dickerson-3 (100)	Chemico	Magnesium Oxide	9/73	90%	$70/kw	12/74 – 64%; now down for turbine overhaul
So. Cal Ed	Mohave-1 (160)	Universal Oil Products	Limestone	11/74			56% since Oct. 31
	Mohave-2 (160)	SCE/Stearns Roger	Lime	11/73	90%		Over 77% since 1/74
TVA	Shawnee-10 (30)	TVA	Lime/ Limestone	4/72			3 types of scrubbers, various tests

New units; all others are retrofit.

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SOLID WASTE COMBUSTION

There is only one electric utility, the Union Electric, Meramac Plant in St. Louis, Missouri, that utilizes solid waste as a fuel on a regular basis. The Union Electric Plant burns municipal refuse (MR) as a supplementary fuel in its coal-burning boilers.[3] However, as shown in Table 78, there are several facilities either under construction or in the planning stage that will use refuse as a fuel.[178] Because of basic differences in boiler design, and lack of solid fuel and ash handling equipment, MR will not be used in oil- or gas-fired units because of their lack of ash handling facilities.

Properties of the Fuel

As shown in Table 79, MR is the most available waste source for the production of energy.[174] About 10 percent of the power required for a typical city could be recovered from its refuse.[175] The physical composition of typical MR is given in Table 80.[175] The composition of MR varies both with the season and the location of its collection. Hence, the actual composition of MR in a given location must be specified precisely to obtain an accurate representation of the pollutant loadings to be expected from any one facility. However, to estimate potential pollutant loadings, average national or regional pollutant compositions are acceptable. The average chemical composition of prepared MR is given in Table 81.[175]

MR is attractive as a fuel for several reasons:

- MR is already collected and shipped to central points in most urban areas, thus alleviating the collection problem.
- MR is ubiquitous and its flow is increasing rather than decreasing, thus its disposal as a fuel is potentially advantageous from an environmental standpoint.
- MR has a low, 0.2 percent, sulfur content rivaling that of the highest grade of coal.[3]

Table 78. PLANNED OR EXISTING REFUSE TO ENERGY SYSTEMS[178]

Location	Number of boilers	Refuse feed rate, ton/hr	Steam rate, lb/hr	Steam temp., °F.	Steam use	Status
St. Louis, Missouri	2	12.5	925,000		Electric generator	OP 1972
Ames, Iowa	3	5.95	360,000	900	Electric generator	UC 1975
		1000 lb/wk	125,000	725		
			95,000	710		
Albany, N.Y.						DSC
Monroe County, N.Y.						C Neg
Memphis, Tenn.						PD
Wilmington, Del.						US

Notes: OP - Operating
UC - Under construction
DSC - Design study complete
C Neg - Contract under negotiation
PD - Preliminary design underway
US - Under study

Table 79. DISTRIBUTION BY SOURCE OF DRY ORGANIC WASTE[2]

Source	Reserve (readily collectable), million tons per year	Resource 1971 (total amount generated), million tons per year	Resource 1980 (total amount generated), million tons per year
Urban refuse	71.0	129	222
Manure	26.0	200	266
Logging and wood manufacturing	5.0	55	59
Agricultural crops and food wastes	22.6	390	390
Industrial wastes	5.2	44	50
Municipal sewage solids	1.5	12	14
Miscellaneous	5.0	50	60
Total	136.3	880	1,061

Table 80. PHYSICAL COMPOSITION OF TYPICAL MUNICIPAL REFUSE

Category	Weight percent (as fired)		Description
	With yard waste	Without yard waste	
Paper	44.2	50.7	Various types, some with fillers
Food waste	16.6	19.1	Garbage
Yard waste	12.6	-	Grass, brush, shrub trimmings
Metal	8.7	10.0	Cans, wire, and foil
Glass	8.5	9.7	Bottles (primarily)
Wood	2.5	2.9	Wooden packaging, furniture, logs, twigs
Textiles	2.3	2.6	Cellulosic, protein, woven synthetics
Leather, rubber and plastics	2.9	3.3	Polyvinyl Chloride, Polyethylene, Styrene, etc., as found in packaging, housewares, toys, and nonwoven synthetics
Miscellaneous	1.7	1.7	Inorganic ash, stones, dust

Table 81. CHEMICAL COMPOSITION OF PREPARED MUNICIPAL REFUSE[176]

Category	Average	Maximum	Minimum
Heating value, Btu/lb:			
As received	4,981	7,593	2,293
Dry	7,248	13,002	6,602
Moisture, wt %:			
Total	31.2	66.3	11.1
Inherent	1.2	2.62	0.36
Ash, wt %:			
As received	15.8	21.4	7.6
Dry	23.1	33.0	14.3
Sulfur, wt %:			
As received	0.10	0.28	0.04
Dry	0.16	0.36	0.07
Chlorine, wt %:			
As received	0.40	0.94	0.14
Dry	0.58	1.14	0.31
Common salt, wt %:			
As received	0.30	0.55	0.11
Dry	0.45	0.76	0.33
Ash analysis, wt %:			
P_2O_5	1.52	2.04	1.06
SiO_2	49.6	56.7	39.9
Al_2O_3	11.3	26.9	6.1
TiO_2	0.89	1.52	0.07
Fe_2O_3	7.89	22.2	3.03
CaO	13.0	15.8	9.09
MgO	1.55	2.32	0.64
SO_3	1.54	2.72	0.73
K_2O	1.78	2.91	1.07
Na_2O	8.70	19.2	3.11
SnO_2	0.05	0.10	0.02
ZnO	0.43	2.25	0.19
CuO	0.28	1.23	0.08
PbO	0.20	0.62	0.12

However, there are disadvantages which will restrict its use by electric utilities. The low heating value of MR is of concern, requiring classification processes to remove noncombustible metals and inorganic materials. The classified refuse has an average heating value of about 4,500 Btu/lb;[75] although this heating value approaches that of some low grade lignite fuels, it is not sufficient for efficient combustion. Thus the use of MR by utilities will be as a supplementary fuel where the waste constitutes only a small percentage of the fuel fired. Used in this manner, the differential effects will be small. Concern has also been expressed about the corrosive effects of MR and ash handling and disposal problems. However, experience at the Meramac Plant has not indicated any serious effect on boiler surfaces. While the fly ash from the Meramac Plant has been successfully used as a cement constituent, marketing of bottom ash as a road bed material does not appear likely because of metal contamination.

The variability of MR characteristics, the seasonal variation in supply, and the lack of full scale demonstration are other factors restricting the use of MR as a supplementary fuel by coal-fired utilities.

Emissions

The Union Electric Plant consists of two facilities.[3] At the first facility the refuse is shredded, ferrous materials removed and air classified. The inorganic fraction is landfilled or sold. The light, organic fraction is trucked to the combustion facility. At the combustion facility the prepared refuse is fed pneumatically into a modified boiler where it is burned in suspension with coal.

Table 82 lists the common air pollutant emissions for different power loads and heat inputs from the refuse. The power load varies from 80 to 120 MW and the maximum sustainable rate of refuse firing is 20 ton/hr. Particulate emissions data are given in Table 83. The difference between the EPA/MRI and the Union Electric Tests is believed to arise from the

Table 82. EMISSION DATA: COAL AND REFUSE FIRING[3]

Stack gas composition corrected to 50% excess air

Load, MW	Heat input from refuse, percent	CO, ppm	SO_2, ppm	NO, ppm	SO_3, ppm	Cl, mg/m^3	Hg, $\mu g/m^3$
80	0	61	882	250	4.0	284	0.017
80	9	75	999	246	4.5	274	0.007
80	18	86	906	403	22.3	419	0.019
80	18	61	NA	317	0.0	374	0.013
80	27	56	804	267	31.3	426	0.010
100	0	73	779	350	0.0	367	0.007
100	9	70	989	233	21.9	385	0.017
100	9	67	899	216	0.0	420	0.019
100	9	59	1,149	249	0.0	332	0.027
100	18	63	1,471	217	0.9	298	0.012
120	0	38	1,031	254	22.1	309	0.013
120	9	60	870	213	0.0	394	0.012
120	9	57	912	316	0.0	418	0.006
120	18	54	920	246	0.0	376	0.017
Mean for 0% refuse		57.33	897.33	284.67	8.7	320	0.012
Standard deviation		(17.79)	(126.7)	(56.62)	(11.78)	(42.58)	(0.005)
Mean for 9% refuse		64.67	969.67	245.5	4.4	370.5	0.015
Standard deviation		(71.18)	(101.63)	(37.59)	(8.76)	(57.03)	(0.008)
Mean for 18% refuse		66.0	1,099	295.75	5.8	366.75	0.015
Standard deviation		(13.88)	(322.24)	(82.83)	(11.01)	(50.32)	(0.003)
One test at 27% refuse		56	804	267	31.3	426	0.010

Table 83. PARTICULATE EMISSION DATA, MEAN AND STANDARD DEVIATION[3]

	Inlet, grain/dscf		Outlet, grain/dscf	
	Mean	Deviation	Mean	Deviation
EPA/MRI Tests:				
Coal				
80 megawatts	1.56	a	0.043	a
100 megawatts	1.80	a	0.050	a
120 megawatts	1.92	a	0.067	a
EPA/MRI Tests:				
Coal plus refuse				
80 megawatts	1.95	0.072	0.037	0.0074
100 megawatts	1.91	0.085	0.062	0.0098
120 megawatts	1.83	0.172	0.065	0.0163
Union Electric Tests:				
Coal				
75 megawatts	1.94	0.025	0.023	0.0025
100 megawatts	2.11	0.163	0.035	0.004
140 megawatts	1.95	0.068	0.060	0.0157
Union Electric Tests:				
Coal plus refuse				
75 megawatts	1.99	0.095	0.045	0
100 megawatts	2.10	0.003	0.073	0.003
140 megawatts	1.91	0.190	0.113	0.0151

[a] Only one test.

Note: EPA - Environmental Protection Agency
MRI - Midwest Research Institute

incomplete breaking in of the precipitators prior to the tests by Union Electric. Water pollutant loadings for the Union Electric Plant are the same as those expected from a tangentially-fired coal burning facility. (These have been discussed elsewhere in this document and will not be elaborated on here.)

The composition of bottom ash changes when municipal refuse is fired. Prior to the use of MR, the bottom ash from the St. Louis plant was sold to highway construction firms. When MR is fired, the bottom ash contains large amounts of unburned wood, metal, and other wastes and must be landfilled. There have been no quantitative studies on the composition of the bottom ash.

Pollutant loadings can be calculated from reported gas flow rates and the emissions factors given in Tables 82 and 83. Table 84 presents the pollutant loadings expected from the Union Electric Plant for 100 MW output power, burning 18 percent MR, and an assumed 8760 operating hours. Actual emissions may be much lower depending on the percentage of MR and the actual operating hours.

Table 84. TOTAL STACK EMISSIONS FOR THE UNION ELECTRIC PLANT[a]

	Emissions,[b,c] 10^3 tons/yr				
Fuel	Particulate	SO_2	NO_x	CO	HC
1.2.40.0.0 (18% MR plus coal)	660	20	1.3	0.37	--

[a] Calculated from test results at 100 MW load and 18 percent refuse.

[b] Total emissions for coal plus MR.

[c] Calculated for a flow rate of 285,348 dscfm.

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SECTION III

INDUSTRIAL COMBUSTION SOURCES

This section presents estimates of air, water, and solid waste pollutants produced by certain types of conventional industrial fossil fuel combustion sources. Fuel combustion usage for steam generation (process steam, space heating, and generation of electricity) and by stationary engines is included while fuel used for feedstock or direct heating is not included.

It is estimated that, within the fuel use categories considered in this study, industrial sources consume 29 percent of the fuel. Industrial fuel is primarily natural gas (67 percent), but oil (18 percent) and coal (12 percent) are used in large quantities. Wood and bagasse represent the remaining 3 percent of industrial fuel consumption.

Many of the principles governing the operation of electric utility boilers apply to industrial boilers. However, industrial boilers consist of a much wider capacity range, from small package boilers of $10\text{-}200 \times 10^6$ Btu/hr to units exceeding 1500×10^6 Btu/hr. Pressure and temperature requirements vary from as low as 2 psig and 215°F for heating applications to as high as 1500 psig and 1000°F for large turbine generators. In this study all boilers used by industry are classified as industrial boilers, although other studies have defined industrial boilers as only those in the $10\text{-}500 \times 10^6$ Btu/hr size range.[1,2]

The type of boiler used in coal-fired installations depends upon coal availability and plant size. While pulverized coal boilers can burn all coals, their lowest practical size is about 200×10^6 Btu/hr. This lower limit is determined by the costs of pulverizers and other auxiliary equipment for smaller units. Cyclone boilers can be used in the size range of 100-800 x 10^6 Btu/hr, and are suitable for low-ash-fusion temperature coals. Many small units less than 200 x 10^6 Btu/hr use stokers as the most practical means of firing coal. Almost any coal can be burned successfully in stoker type boilers. The spreader stoker is the most common firing method used for intermediate size boilers, up to 250 x 10^6 Btu/hr.

Natural gas- and oil-fired boilers are similar to utility boilers and can be used for all capacities. By-product gas, bagasse, wood, and other waste materials are available in many industrial areas and are often utilized in industrial boilers. The availability of these cheap fuels is often the decisive factor influencing industries to install electric generation equipment. Otherwise, electricity might be more economically purchased from a utility.

The use of internal combustion engines (gas turbines and reciprocating engines) is more prevalent in the industrial sector than in the electric utility sector. Internal combustion engines account for almost 25 percent of the industrial fuel use as opposed to 4 percent in electric utilities. The greater use of internal combustion engines is largely based on their adaptability to required variations in demand and their simple operation. The gas turbine is replacing the reciprocating engine because of its lower installed cost per horsepower and its greater reliability.

DATA SOURCES

Previous industrial combustion studies have used NEDS data,[3] sales figures available from the American Boiler Manufacturers Association,[4] and U.S. Department of Commerce census data[5] to define boiler capacity and population. There is less information available in the technical literature concerning operating and emission control practices of industrial fuel consumers than is available on the utility sector.

Emission control information for air pollutants is available in the NEDS data file for combustion sources emitting more than 100 tons/year of any criteria pollutant. This emission rate is characteristic of uncontrolled boilers which are greater than or equal to the following capacities:

• Bituminous coal-fired	4×10^6 Btu/hr
• Residual oil-fired	13×10^6 Btu/hr
• Natural gas-fired	110×10^6 Btu/hr

These minimum capacities vary with fuel ash content, sulfur content, and boiler operating hours. Many industrial boilers do not appear in the NEDS file because they are below the minimum capacities.

The characteristics of industrial boilers have been studied in several recent EPA programs. Emissions and control techniques at 50 coal-, oil-, and gas-fired boilers in the 10-500 x 10^6 Btu/hr size range have been extensively investigated by KVB in a continuing series of tests.[6] Particulate control device application for industrial coal-fired units in the size range 10-500 x 10^6 Btu/hr, as specified in NEDS data, has been analyzed by Monsanto Research Corporation (MRC).[7,8] Midwest Research Institute (MRI) has also estimated control efficiency for industrial coal-fired boilers.[9] MRC estimated an overall control efficiency of 50 percent, while MRI estimated 60 percent for coal-fired boilers. We were unable to update control equipment efficiency through the NEDS file as point source printouts were unavailable from EPA in the time frame of the project due to computer problems. The emission estimates provided in this section of the report are based on the limited data presently available. More extensive data on industrial boilers larger than 100 x 10^6 Btu/hr capacity are being compiled by the Federal Energy Administration.

Oil, gas, and coal consumption were calculated from Bureau of Mines data.[10-13] NEDS as well as other data sources were used to estimate consumption of minor fuels such as anthracite, wood, and bagasse. As will be noted, these data sources generally yield lower fuel consumption values than estimates by MRC.[7,8]

The quantity and characteristics of waste water and solid waste emissions from industrial combustion sources are not extensively reported in the technical literature. In addition, investigation into methods of controlling these emissions has received little attention. The National Pollution Discharge Elimination System permit program is a potential source of information, but cannot yet be used for data that are statistically meaningful. In estimating water and solid waste pollutants, we have assumed that industrial and utility practices are similar for the large boilers. Descriptions of these practices provided by knowledgeable individuals were also utilized.

FUEL CONSUMPTION

Industrial combustion fuel consumption included in this project includes fossil and solid waste fuels used for steam generation and space heating or in stationary engines. Fuel used for direct heating in applications such as kilns, coking, and other metallurgical and mineral processing operations is not included. Consumption of fuel as feedstock is also not included. A number of data sources are available for estimating industrial fuel usage,[10-16] but estimates vary due to differences in definitions of industrial fuel use.

GCA's estimates of industrial fuel consumption are based primarily on Bureau of Mines data[10-13] (coal, oil, and gas) and NEDS data[3] (wood and bagasse). Coal consumption for steam generation and space heating was estimated to be 61,620,000 tons/year. (This is only a portion of the total industrial coal consumption, as about 90,000,000 tons/year are used for coking.[17]) Similarly, oil consumption reported in Table 85 represents less than half the total used by industry, as large amounts are used as feedstocks and for direct heat.[15] Natural gas consumption by external combustion systems was calculated by subtracting the amount used in internal combustion systems and then subtracting direct heat and feedstock consumption (about 35 percent).[15] Bagasse and wood consumption were calculated from emissions reported by the NEDS system.[3] During 1973, only four large scale systems with a total capacity of 10×10^{12} Btu/hr were burning refuse to produce steam (see Table 105). These systems have had operating problems, have probably operated at load factors near 20 percent, and most of the steam produced has not been utilized.[18] The small amount of refuse burned has not been included in any of the summary tables but is discussed in a later section. Fuel consumption by gas turbines and reciprocating engines was estimated from capacity and average load data.[19]

Our fuel consumption estimates for both coal- and oil-fired boilers are considerably lower (~50 percent) than estimates prepared by MRC.[6,7] MRC calculated fuel consumption from boiler population data[20] and generalized load factors and combustion efficiencies.[21] The generalized load factors were based on very little real data, and therefore fuel consumption estimates based on Bureau of Mines data were used whenever possible.

Natural gas accounts for 67 percent of industrial fuel usage, oil for 18 percent, and coal for 12 percent (see Table 85). External combustion sources account for 77 percent of the total with internal combustion accounting for the remaining 23 percent. Natural gas represents 61 percent of external combustion fuel, while coal and oil represent 16 and 15 percent, respectively, of external combustion fuel. Bagasse accounts for only 0.2 percent of external combustion fuel, and wood accounts for 3 percent. Municipal refuse represents less than 0.05 percent.

Table 85. INDUSTRIAL FUEL CONSUMPTION, 1973

		Amount used	10^{12} Btu
2.0.00.0.0	Industrial		11,300
2.1.00.0.0	External combustion		8,540
2.1.10.0.0	Coal[a]	60,620	1,370
2.1.11.0.0	Bituminous	57,450	1,320
2.1.12.0.0	Anthracite	370	10
2.1.13.0.0	Lignite	2,800	40
2.1.20.0.0	Petroleum[b]	11,400,000	1,700
2.1.21.0.0	Residual	8,400,000	1,270
2.1.22.0.0	Distillate	3,000,000	430
2.1.30.0.0	Natural gas[c]	5,200,000	5,200
2.1.41.0.0	Bagasse[a]	4,300	20
2.1.42.0.0	Wood[a]	28,000	250
2.2.00.0.0	Internal combustion	5,000,000	2,760
2.2.20.0.0	Petroleum[b]	2,600,000	360
2.2.30.0.0	Natural gas[c]	2,400,000	2,400

[a] In thousands of tons.

[b] In thousands of gallons.

[c] In 10^6 cubic feet (includes LPG).

Industrial fuel consumption data by state are presented in Appendix B. The same eight states (Kentucky, Illinois, Indiana, Michigan, Ohio, Pennsylvania, Tennessee, and West Virginia) that consume 58 percent of utility coal, consume 68 percent of industrial coal. Only 10 percent of the total industrial coal is consumed in the western half of the U.S. Natural gas consumption is concentrated in Texas and Louisiana where 35 percent of the total is consumed. Consumption of oil is more evenly distributed, but the largest amounts are used in the east. One-third of the oil is consumed in the adjacent states of Illinois, Indiana, Ohio, Pennsylvania, New York, and New Jersey. Bagasse is burned in large quantities in Hawaii (72 percent of total), Florida (17 percent), and Louisiana (11 percent).[3] Wood is burned primarily in the Northwest (33 percent) and the South Atlantic region (29 percent).[3]

POPULATION AND CHARACTERISTICS OF COMBUSTION EQUIPMENT

Coal-, Oil-, and Gas-Fired Boilers

The number of industrial boilers and plants is much greater than the number of utility units. For this reason there have been no attempts to conduct an inventory of all industrial boilers. The most widely used boiler population data[1,2,7,8] were originally developed by Battelle for API and EPA and are based primarily on sales data.[20] A recent Battelle report states: "Unfortunately, there is no fully satisfactory source of statistics on the actual number or the installed capacity of boilers now in field service. Sales records, even if available for many years, would not be adequate because a field conversion from one fuel to another is not reflected in sales records."[2] In addition, sales data do not reflect boiler shutdowns due to business failures or other operational changes.

Despite the uncertainties involved in estimating industrial boiler populations, such an estimate can be useful and, therefore, the best available description of industrial boiler size and capacity is presented in Table 86. The data in the size range 10-500 x 10^6 Btu/hr are based on an analysis by Battelle Columbus Laboratories[1] of NEDS data, supplemented with sales information from the American Boiler Manufacturers Association (ABMA)[4] and the Department of Commerce.[5] The data for boilers above 500 x 10^6 Btu/hr are based solely on NEDS data. Boilers above 500 x 10^6 Btu/hr represent 25 percent of coal-fired boiler capacity and only 8 percent and 11 percent of oil- and gas-fired capacity, respectively.

Table 86. TOTAL CAPACITIES OF INDUSTRIAL BOILERS, 1973[1,22]

Size, 10^6 Btu/hr	Capacity, 10^9 Btu/hr						
	Coal	Coal[a] and other	Oil	Oil[a] and gas	Gas	Gas[a] and oil	All fuels
10-20	10	10	180	310	90	160	480
20-50	20	30	110	160	60	310	500
50-100	60	70	140	190	50	370	630
100-200	90	130	120	160	80	230	520
200-500	150	290	160	210	100	200	700
> 500	90	180	60	80	50	140	400
Totals	420	710	770	1110	430	1410	3230

[a] Includes boilers designed to burn the primary fuel only, as well as those capable of burning a secondary fuel.

Table 87. NUMBER AND SIZE OF INDUSTRIAL BOILERS, 1973[1,22]

Size, 10^6 Btu/hr	Number of boilers			
	Coal[a]	Oil[a]	Gas[a]	All fuels
10-20	670	21,000	11,000	32,670
20-50	860	4,600	8,900	14,360
50-100	930	2,500	4,900	8,330
100-200	870	1,100	1,500	3,470
200-500	830	600	570	2,000
> 500	70	135	90	295
Totals	4,230	29,935	26,960	61,125

[a] Includes boilers designed to burn the primary fuel only, as well as those capable of burning a secondary fuel.

The number of boilers in each size fuel category was estimated from the capacity and the average of the size range and is presented in Table 87.

Table 88 presents estimates of boiler capacities and fuel consumption by detailed combustion system classification. The estimates of fuel consumption within the bituminous coal category were based on the boiler size data (Table 86) and the associated boiler type and combustion efficiency within each size category.[1,21] In addition, the average load factors within each category were considered. In the case of anthracite and lignite, however, all fuel consumption has been assigned to stoker boilers because over 90 percent of the boilers burning these fuels do so in stokers.[3]

The capacity of oil- and gas-fired boilers using tangential firing was determined by assuming that boilers larger than 100 x 10^6 Btu/hr were similar to utility boilers. Therefore, 16 percent of oil-fired and 10 percent of gas-fired industrial boilers are estimated to use tangential firing patterns.

Solid Waste-Fired Boilers

Wood/bark may be burned in stoker-fired boilers, and in systems similar to pulverized coal firing (i.e., tangential firing), at capacities up to 1000 x 10^6 Btu/hr.[23] Bagasse can also be burned in both stoker-fired boilers and by suspension firing.[24] Boiler input heat rates to 600 x 10^6 Btu/hr have been reported.[25] Municipal refuse will be burned in stoker-type boilers (mainly traveling grates) and may be burned in suspension if properly pulverized and classified.[18] The majority of the nonutility systems appear to be using various traveling grate arrangements.[18] At this time, the largest refuse burning boiler is the Chicago Northwest Incinerator with a capacity of nearly 700 x 10^6 Btu/hr.[18] The total municipal refuse generated in the U.S. has a heating value of 1433 x 10^{12} Btu compared to the 38,700 x 10^{12} Btu consumed by the stationary combustion sources included in this study.[26]

Table 88. INDUSTRIAL BOILER CAPACITY AND FUEL CONSUMPTION BY COMBUSTION SYSTEM, 1973

		Approximate design capacity, 10^9 Btu/hr steam	Fuel consumed, 10^{12} Btu/yr
2.0.00.0.0	Industrial	3,700	11,280
2.1.00.0.0	External combustion	3,230	8,540
2.1.10.0.0	Coal	730	1,370
2.1.11.0.0	Bituminous	690	1,320
2.1.11.1.0	Pulverized dry	330	650
2.1.11.2.0	Pulverized wet	70	130
2.1.11.3.0	Cyclone	10	40
2.1.11.4.0	All stokers	280	500
2.1.11.5.0	Overfeed stokers	25	30
2.1.11.6.0	Spreader stokers	235	450
2.1.11.7.0	Underfeed stokers	20	20
2.1.12.0.0	Anthracite	8	10
2.1.12.1.0	Pulverized dry	0	0
2.1.12.2.0	Pulverized wet	0	0
2.1.12.4.0	All stokers	8	10
2.1.13.0.0	Lignite	20	40
2.1.13.1.0	Pulverized dry	0	0
2.1.13.2.0	Pulverized wet	0	0
2.1.13.4.0	All stokers	20	40
2.1.13.5.0	Overfeed stokers	0	0
2.1.13.6.0	Spreader stokers	20	40
2.1.13.7.0	Underfeed stokers	0	0
2.1.20.0.0	Petroleum	1,110	1,700
2.1.21.0.0	Residual oil	850	1,270
2.1.21.0.1	Tangential firing	140	200
2.1.21.0.2	All other	710	1,070
2.1.22.0.0	Distillate oil	260	430
2.1.22.0.1	Tangential firing	40	70
2.1.22.0.2	All other	220	360
2.1.30.0.0	Gas	1,410	5,200
2.1.30.0.1	Tangential firing	140	520
2.1.30.0.2	All other	1,270	4,680
2.1.40.0.0	Refuse		270
2.1.41.0.0	Bagasse		20
2.1.42.0.0	Wood/Bark		250

Internal Combustion

Internal combustion engines are used in the utility industry at only a few percent of capacity. However, industrial requirements for a large number of small, fairly simple, reliable units for pipeline transmission of oil and gas result in increased use of internal combustion engines. In addition, the requirement for numerous startups and shutdowns, as in agricultural irrigation, favors internal combustion engines.

For the year 1971, gas turbines operated at an average of 55 percent of capacity and reciprocating engines operated at an average of 58.1 percent of capacity.[19] In that year, the power generating capacity of gas turbines amounted to 35.5 million horsepower whereas the power generating capacity of reciprocating engines amounted to 34.7 million horsepower, of which 73 percent was for industrial use, including 35.2 percent for transmission of oil and natural gas in pipelines, 9.3 percent for natural gas production, 6 to 9 percent for natural gas processing, and 22 percent for agricultural irrigation.[19] Fuel consumption data for 1971 were available,[19] and the 1973 consumption was estimated to be relatively the same because total U.S. natural gas consumption was constant[16] and most engines are used in the natural gas and petroleum industries. Capacity and fuel consumption data for industrial internal combustion engines are presented in Table 89.

Very little data are available on the size and number of internal combustion engines. The majority of sales during 1973 were below 1,000 hp[27] (~8-11 x 10^6 Btu/hr heat input). However, some new pipeline operations are using gas turbines in the 10,000-20,000 hp range. Based on the available data,[19,27] a rough estimate would be 100,000 units with an average size of 600 hp (~4.8-6.6 x 10^6 Btu/hr heat input).

Table 89. INDUSTRIAL INTERNAL COMBUSTION - FUEL CONSUMPTION

		Capacity, 1000 hp[a]	Fuel consumption, 10^{12} Btu
2.0.00.0.0	Industrial		
2.2.00.0.0	Internal combustion	59,343	2,760
2.2.20.0.0	Petroleum[b]	8,223	360
2.2.30.0.0	Natural gas[c]	51,120	2,400
2.3.00.0.0	Gas turbines	29,989	1,490
2.3.20.0.0	Petroleum	1,864	90
2.3.21.0.0	Residual oil	0	0
2.3.22.0.0	Distillate oil	1,864	90
2.3.30.0.0	Natural gas	28,125	1,400
2.4.00.0.0	Reciprocating engines	29,354	1,270
2.4.20.0.0	Petroleum	6,359	270
2.4.21.0.0	Residual oil	0	0
2.4.22.0.0	Distillate oil	6,359	270
2.4.30.0.0	Natural gas	22,995	1,000

[a] Capacity is energy output in horsepower. One horsepower output is equivalent to 0.75 kW output and 8,000-11,000 Btu/hr input.

[b] 140,000 Btu/gal.

[c] 1,022 Btu/scf.

FLUE GAS EMISSIONS

Industrial combustion sources are a major contributor of air pollutant emissions to the environment. Based on this study, industry's contribution to the "man-made" criteria pollutant discharges to air are as shown in Table 90. The majority of air pollutant emissions are from the combustion stack.

Table 90. THE INDUSTRIAL COMBUSTION SOURCE CONTRIBUTION TO AIR POLLUTANT EMISSIONS

Pollutant	Percent of U.S. total man-made emissions	Percent of stationary combustion source emissions
Particulate	6	28
SO_x	10	14
NO_x	11	25
HC	0.2	22
CO	0.1	15

Total nationwide emission estimates of particulates (including <3 micron diameter particulates), sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, polycyclic organic matter, and trace elements are presented in the following subsections for the industrial combustion sector.

External Combustion

Combustion of fuel for the generation of electricity, space heating, and process steam by industry via external combustion accounts for 6 percent of total particulates, 10 percent of sulfur oxides, 7 percent of nitrogen oxides, 0.2 percent of hydrocarbons, and 0.1 percent of carbon monoxide emissions from all man-made sources. Industrial external combustion accounts for 28 percent of total particulates, 14 percent of sulfur oxides, 15 percent of nitrogen oxides, 21 percent of hydrocarbons, and 14 percent of carbon monoxide emissions from conventional stationary combustion sources.

Detailed emission estimates for the United States are presented in Table 91. The estimates of criteria pollutants are based on the EPA-NEDS emission factors[28] listed in Table 92 and the methods described in the notes following Table 91.

Table 91. FLUE GAS EMISSIONS[a] FROM INDUSTRIAL EXTERNAL COMBUSTION

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[i] tons/yr		
		Total	<3μ[k]	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
2.0.00.0.0	Industrial	2,000	200	3,200	2,700	80	160	25,000	20	5
2.1.00.0.0	External Combustion	2,000	200	3,200	1,600	76	150	25,000	20	5
2.1.10.0.0	Coal	2,000	66	2,200	590	17	73	2,800	16	4.0
2.1.11.0.0	Bituminous[b]	1,600	65	2,200	570	16	57	2,700	15	3.8
2.1.11.1.0	Pulverized Dry	610	29	1,100	260	4.3	15	1,200	7.2	1.8
2.1.11.2.0	Pulverized Wet	99	4.8	220	87	0.87	2.9	250	1.4	0.36
2.1.11.3.0	Cyclone	6	3.8	68	49	0.27	0.89	50	0.29	0.072
2.1.11.4.0	All Stokers	900	27	850	170	11	22	1,200	7.7	1.7
2.1.11.5.0	Overfeed Stokers	54	1.5	51	10	0.66	1.3	97	0.56	0.14
2.1.11.6.0	Spreader Stokers	810	24	770	150	9.9	20	970	5.6	1.4
2.1.11.7.0	Underfeed Stokers	36	1.1	34	6.8	0.44	0.88	97	0.56	0.14
2.1.12.0.0	Anthracite[c]	6.3	0.12	7.3	1.9	0.055	1.7	19	0.11	0.028
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers	6.3	0.12	7.3	1.9	0.055	1.7	19	0.11	0.028
2.1.13.0.0	Lignite[d]	35	0.68	25	18	1.4	14	90	0.52	0.13
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers	35	0.68	25	18	1.4	14	90	0.52	0.13
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers	35	0.68	25	18	1.4	14	90	0.52	0.13
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum[e]	120	110	1,000	430	15	21	11,000	1.4	0.36
2.1.21.0.0	Residual Oil	97	87	1,000	320	11	15	8,600	1.1	0.27
2.1.21.0.1	Tangential Firing	15	14	160	27	2	3	940	0.12	0.03
2.1.21.0.2	All Other	82	73	840	290	9	12	7,600	0.96	0.24
2.1.22.0.0	Distillate Oil	21	19	41	110	4.2	5.7	2,400	0.38	0.094
2.1.22.0.1	Tangential Firing	3	3	6	10	0.66	0.89	280	0.044	0.011
2.1.22.0.2	All Other	18	16	35	100	3.5	4.8	2,100	0.33	0.083
2.1.30.0.0	Gas[f]	25	23	1.4	420	7.7	41	11,000	2.2	0.55
2.1.30.0.1	Tangential Firing	2.5	2.3	0.14	42	0.77	4.1	2,000	0.4	0.10
2.1.30.0.2	All Other	22	21	1.3	380	6.9	37	9,000	1.8	0.45
2.1.41.0.0	Bagasse[g]	42		0	5.5	5.5	5.5			
2.1.42.0.0	Wood/Bark[h]	210		18	140	31	44			

Table 91 (continued). FLUE GAS EMISSIONS[a] FROM INDUSTRIAL EXTERNAL COMBUSTION

		Trace elements,[j] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
2.0.00.0.0	Industrial	5.8	260	490	25	9.1	490	870	67	93,000	200
2.1.00.0.0	External Combustion	5.8	260	490	25	9.1	490	870	67	93,000	200
2.1.10.0.0	Coal[k]	4.5	250	470	22	9.1	490	860	3.7	92,000	140
2.1.11.0.0	Bituminous[l]	4.5	250	330	22	9.0	470	860	3.7	86,000	130
2.1.11.1.0	Pulverized Dry	2.3	130	170	11	4.5	240	420	1.9	42,000	65
2.1.11.2.0	Pulverized Wet	0.34	19	25	1.6	0.69	36	85	0.28	8,500	9.9
2.1.11.3.0	Cyclone	0.022	1.2	1.6	0.11	0.043	2.3	11	0.018	2,600	0.63
2.1.11.4.0	All Stokers	1.8	100	130	8.8	3.7	190	330	1.5	33,000	53
2.1.11.5.0	Overfeed Stokers	0.11	6.1	8.0	0.52	0.22	12	20	0.090	2,000	3.1
2.1.11.6.0	Spreader Stokers	1.6	92	120	7.8	3.3	170	290	1.3	29,000	47
2.1.11.7.0	Underfeed Stokers	0.072	4.0	5.2	0.34	0.14	7.6	13	0.059	1,300	2.1
2.1.12.0.0	Anthracite[m]		0.04	3.4	0.17			0.37		550	7.0
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers	0	0.04	3.4	0.17	0	0	0.37		550	7.0
2.1.13.0.0	Lignite[n]		0	140	0.13	0.08	19	0.036		5,500	1.9
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers			140	0.13	0.08	19	0.036		5,500	1.9
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers			140	0.13	0.08	19	0.036		5,500	1.9
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum	1.3	11	21	3.0		3.6	5.8	63	530	58
2.1.21.0.0	Residual Oil[o]	1.3	10	21	3.0		3.6	5.7	63	530	58
2.1.21.0.1	Tangential Firing	0.20	1.6	3.3	0.47		0.56	0.89	9.9	83	9.1
2.1.21.0.2	All Other	1.1	8.4	18	2.5		2.9	4.9	53	450	49
2.1.22.0.0	Distillate Oil[p]	ND	0.50	ND				0.11	ND		ND
2.1.22.0.1	Tangential Firing	ND	0.034	ND				0.018	ND		ND
2.1.22.0.2	All Other	ND	0.37	ND				0.092	ND		ND
2.1.30.0.0	Gas[q]										
2.1.30.0.1	Tangential Firing										
2.1.30.0.2	All Other										
2.1.41.0.0	Bagasse										
2.1.42.0.0	Wood/Bark										

Table 91 (continued). FLUE GAS EMISSIONS[a] FROM INDUSTRIAL EXTERNAL COMBUSTION

		Trace elements,[j] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
2.0.00.0.0	Industrial	110	460	4,800	33,000	86	510	8.1	110	1,700	110
2.1.00.0.0	External Combustion	110	460	4,800	33,000	86	510	8.1	110	1,700	110
2.1.10.0.0	Coal[k]	42	130	4,800	32,000	85	510	7.4	34	130	110
2.1.11.0.0	Bituminous[l]	34	120	4,700	32,000	81	480	7.3	33	130	110
2.1.11.1.0	Pulverized Dry	17	58	2,300	16,000	41	210	3.6	17	65	55
2.1.11.2.0	Pulverized Wet	2.6	8.7	460	2,400	6.2	31	0.72	2.5	9.9	11
2.1.11.3.0	Cyclone	0.17	0.57	140	150	0.40	15	0.22	0.16	0.63	3.4
2.1.11.4.0	All Stokers	14	47	1,800	13,000	33	180	2.8	13	53	42
2.1.11.5.0	Overfeed Stokers	0.82	2.8	110	760	2.0	10	0.17	0.80	3.1	2.5
2.1.11.6.0	Spreader Stokers	12	41	1,600	11,000	29	160	2.5	12	47	38
2.1.11.7.0	Underfeed Stokers	0.54	1.8	70	500	1.3	6.6	0.11	0.52	2.1	1.7
2.1.12.0.0	Anthracite[m]	5.6	4.6	59	420	0.56	0.84	0.091	0.04	3.0	0.051
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers	5.6	4.6	59	420	0.56	0.84	0.091	0.04	3.0	0.051
2.1.13.0.0	Lignite[n]	2.5	4.2			3.0	25		0.7	1.4	
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers	2.5	4.2			3.0	25		0.7	1.4	
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers	2.5	4.2			3.0	25		0.7	1.4	
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum	70	330	0.13	235	1.3	5.0	0.65	72	1,600	4.5
2.1.21.0.0	Residual Oil[o]	70	330	0.13	235	1.3	5.0	0.65	72	1,600	4.5
2.1.21.0.1	Tangential Firing	11	52	0.020	37	0.20	0.79	0.10	11	250	0.71
2.1.21.0.2	All Other	59	280	0.11	200	1.1	4.2	0.55	61	1,300	3.8
2.1.22.0.0	Distillate Oil[p]		0.25				0.066	ND		ND	ND
2.1.22.0.1	Tangential Firing		0.016				0.011	ND		ND	ND
2.1.22.0.2	All Other		0.023				0.055	ND		ND	ND
2.1.30.0.0	Gas[q]										
2.1.30.2.1	Tangential Firing										
2.1.30.0.2	All Other										
2.1.41.0.0	Bagasse										
2.1.42.0.0	Wood/Bark										

Table 91 (continued). FLUE GAS EMISSIONS[a] FROM INDUSTRIAL EXTERNAL COMBUSTION

		Trace elements,[j] tons/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
2.0.00.0.0	Industrial	2.8	0.90	18	5,600	180	2,100	220	460
2.1.00.0.0	External Combustion	2.8	0.90	16	5,600	180	2,100	220	460
2.1.10.0.0	Coal[k]	2.8	0.90	9.9	5,400	140	260	210	460
2.1.11.0.0	Bituminous[l]	2.8	0.90	8.6	5,400	140	250	200	420
2.1.11.1.0	Pulverized Dry	1.4	0.45	4.3	2,700	68	130	99	210
2.1.11.2.0	Pulverized Wet	0.21	0.069	0.66	400	10	19	15	32
2.1.11.3.0	Cyclone	0.013	0.0043	0.043	26	0.67	1.2	0.97	2.0
2.1.11.4.0	All Stokers	1.1	0.37	3.5	2,200	55	100	80	170
2.1.11.5.0	Overfeed Stokers	0.065	0.022	0.21	130	3.3	6.0	4.7	10
2.1.11.6.0	Spreader Stokers	0.98	0.33	3.1	1,900	49	90	71	150
2.1.11.7.0	Underfeed Stokers	0.043	0.014	0.14	84	2.2	4.0	3.1	6.7
2.1.12.0.0	Anthracite[m]				35		0.81	2.0	2.9
2.1.12.1.0	Pulverized Dry	0	0	0	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0	0	0	0
2.1.12.4.0	All Stokers				35		0.81	2.0	2.9
2.1.13.0.0	Lignite[n]			1.3			4.2	5.3	39
2.1.13.1.0	Pulverized Dry	0	0	0	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0	0	0	0
2.1.13.4.0	All Stokers			1.3			4.2	5.3	39
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0	0	0	0
2.1.13.6.0	Spreader Stokers			1.3			4.2	5.3	39
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0	0	0	0
2.1.20.0.0	Petroleum				170	44	1,800	6.0	
2.1.21.0.0	Residual Oil[o]				170	44	1,800	6.0	
2.1.21.0.1	Tangential Firing				27	6.9	280	0.94	
2.1.21.0.2	All Other				140	37	1,500	5.1	
2.1.22.0.0	Distillate Oil[p]			5.6			ND	ND	
2.1.22.0.1	Tangential Firing			0.90			ND	ND	
2.1.22.0.2	All Other			4.7			ND	ND	
2.1.30.0.0	Gas[q]								
2.1.30.0.1	Tangential Firing								
2.1.30.0.2	All Other								
2.1.41.0.0	Bagasse								
2.1.42.0.0	Wood/Bark								

Table 91 (continued). FLUE GAS EMISSIONS[a] FROM INDUSTRIAL EXTERNAL COMBUSTION

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[a] Values in the table represent total estimated emissions to the atmosphere from conventional stationary combustion sources in the United States. An entry of "ND" signifies that a trace element has not been detected when measured; and an entry left blank signifies that no information is available. The emission factors used in this table are given in Table 92.

[b] The consumption of bituminous coal was taken from Table II, page 39, of reference 10 under the column headed "All others." The percentage of boilers using controls for particulates was multiplied by the average particulate control efficiencies for each boiler type and subtracted from unity to obtain the fractions of the total particulates that escape. These escape numbers are 0.19 for pulverized units, 0.48 for stokers, and 0.25 for cyclones. The sulfur and ash contents of the coal were assumed to be equal to those for coal used by electric utilities for each state; these were taken from Table 1-A, page 1, of reference 29.

[c] The emissions from anthracite combustion are from the 1972 NEDS Report.[3]

[d] The consumption of lignite was taken from reference 30.

[e] The consumption of oil was taken from Tables 8 and 9, pages 6 and 7, of reference 11. The sulfur content of the oils was taken from reference 31 for 1973 oils, which gives the average sulfur content by geographical region. (Any state falling into more than one region was assigned a sulfur content corresponding to the average of those regions.)

[f] The consumption of natural gas was taken from Table 7, page 8, of reference 12. The consumption data for liquified petroleum gas was taken from Table 5, page 7, of reference 13. The emissions listed for "Gas" are summations of the emissions for natural gas and LPG.

[g] The emissions for bagasse were taken from the 1972 NEDS Report.[3]

[h] The consumption of wood was calculated from the emissions reported in the 1972 NEDS Report.[3] This consumption figure was then updated to 1975, using a growth rate of 1.2 percent per year. The updated consumption data were then used to calculate the emissions.

[i] The emissions of BaP and BSO from all fuels were calculated from emission factors in reference 32. The emissions of particulate polycyclic organic matter (PPOM) from coal were based on a summation of emission factors for Pyrene, Benzo(a)pyrene, Benzo(c)pyrene, Perylene, Benzo(ghi)-perylene, Anthanthrene, Coronene, Anthracene, Phenanthrene, and Fluoranthene. PPOM emissions from oil and gas were calculated by assuming

Table 91 (continued): FLUE GAS EMISSIONS[a] FROM INDUSTRIAL EXTERNAL COMBUSTION

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the same ratio to BaP as in the case of coal. Emission factors were specific to intermediate size combustion equipment. No data were found on emissions of polyhalogenated biphenyls from conventional industrial combustion.

[j] The amount of each trace element, i, emitted to the atmosphere was calculated as follows:

(1) The amount of i in the fuel, A_i, was

$$A_i = C_i \times F_i$$

where C_i = concentration of i in the fuel, ppm

F_i = yearly consumption of fuel, tons/year.

If A_i was calculated on a regional basis, results were summed to the national level.

(2) The amount emitted to the atmosphere, E_i, was

$$E_i = A_i \times f_i \ .$$

For coal-fired pulverized dry bottom units $f_i = 0.16$, for pulverized wet bottom units $f_i = 0.12$, for cyclone units $f_i = 0.025$, and for stokers $f_i = 0.17$. Exceptions are Br, Cl, and F for which $f_i = 1.0$, Hg for which $f_i = 0.90$, and Se for which $f_i = 0.70$. For oil-fired units $f_i = 1.0$, where f_i = estimated fraction of i emitted to the atmosphere.

[k] Data for coal were available for each of the coal-producing regions defined by the U.S. Geological Survey. Sources of trace element concentration data were publications by Magee,[33] Zubovic,[34] Kessler,[35] Ruch,[36] and von Lehmden.[37]

[l] For each coal-producing region concentrations of As, Ba, Be, B, Cr, Co, Cu, F, Pb, Mn, Hg, Mo, Ni, Sn, U, V, and Zn in bituminous coal were calculated using reference 33 as a primary source and reference 34 as a supplementary source. For Cl, Br, and Ti, data from Illinois in reference 36 were used as typical of all coal-producing regions. For Sb, Bi, Cd, Fe, Te, Tl, and Zr, concentrations were calculated by using reference 35. For Se, the single concentration cited by reference 38 was used.

[m] For anthracite coal, typical trace element concentrations were taken from reference 35.

Table 91 (continued). FLUE GAS EMISSIONS[a] FROM INDUSTRIAL EXTERNAL COMBUSTION

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[n] For lignite, reference 33 supplied the data for North Dakota lignite, and reference 34 supplied the data for Texas lignite. Reference 33 contained data for the elements As, Ba, Be, Bi, B, Br, Co, Cu, Cr, Mn, Mo, Ni, Sn, V, Zn, and Zr. Reference 34 contained data for the elements Be, Br, Co, Cu, Mo, Ni, Sn, V, and Zr. A concentration of Cl in lignite was obtained from reference 39.

[o] For residual oil, trace element concentration data were available for As, Sb, Ba, Br, Cr, Mn, Ni, V, and Zn from reference 40. For the trace elements Be, B, Cd, Co, F, Fe, Pb, Hg, Mo, Se, Sn, Ti, and U, reference 41 was used as the primary source and references 37, 41, 42, and 43 as supplementary sources.

[p] For distillate oil, reference 40 reported concentrations for As, Br, Cu, Mn, and Sn, and reported that Sb, Ba, Cd, Cr, Hg, Ni, Se, V, and Zn were not detectable.

[q] Hydrocarbon gases were assumed to be free of trace elements.

[r] Emissions of <3 micron particles were estimated from data in reference 8 indicating for industrial coal combustion the fraction of mass emissions that were <3 microns. These fractions were 0.0484, 0.626, and 0.0295 for pulverized, cyclone, and stoker-fired boilers, respectively. For oil and gas, 90 percent of the total particulate was assumed to be <3 microns.

Table 92. EMISSION FACTORS FOR TABLE 91

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
2.0.00.0.0	Industrial	NA	NA	NA	NA	NA
2.1.00.0.0	External Combustion	NA	NA	NA	NA	NA
2.1.10.0.0	Coal[b]	NA	NA	NA	NA	NA
2.1.11.0.0	Bituminous	NA	NA	NA	NA	NA
2.1.11.1.0	Pulverized Dry	16A	38S	18	0.3	1
2.1.11.2.0	Pulverized Wet	13A	38S	30	0.3	1
2.1.11.3.0	Cyclone	2A	38S	55	0.3	1
2.1.11.4.0	All Stokers	13A	38S	15	1	2
2.1.11.5.0	Overfeed Stokers	13A	38S	15	1	2
2.1.11.6.0	Spreader Stokers	13A	38S	15	1	2
2.1.11.7.0	Underfeed Stokers	13A	38S	15	1	2
2.1.12.0.0	Anthracite	2A	38S	15	0.2	10
2.1.12.1.0	Pulverized Dry	X	X	X	X	X
2.1.12.2.0	Pulverized Wet	X	X	X	X	X
2.1.12.4.0	All Stokers	2A	38S	15	0.2	10
2.1.13.0.0	Lignite	6.5A	30S	13	1	2
2.1.13.1.0	Pulverized Dry	X	X	X	X	X
2.1.13.2.0	Pulverized Wet	X	X	X	X	X
2.1.13.4.0	All Stokers	6.5A	30S	13	1	2
2.1.13.5.0	Overfeed Stokers	X	X	X	X	X
2.1.13.6.0	Spreader Stokers	6.5A	30S	13	1	2
2.1.13.7.0	Underfeed Stokers	X	X	X	X	X

Table 92 (continued). EMISSION FACTORS FOR TABLE 91

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
2.1.20.0.0	Petroleum[c]	NA	NA	NA	NA	NA
2.1.21.0.0	Residual Oil	NA	NA	NA	NA	NA
2.1.21.0.1	Tangential Firing	23	159S	40	3	4
2.1.21.0.2	All Other	23	159S	80	3	4
2.1.22.0.0	Distillate Oil	NA	NA	NA	NA	NA
2.1.22.0.1	Tangential Firing	15	144S	40	3	4
2.1.22.0.2	All Other	15	144S	80	3	4
2.1.30.0.0	Gas[d]	10	0.6	175	3	17
2.1.30.0.1	Tangential Firing	10	0.6	175	3	17
2.1.30.0.2	All Other	10	0.6	175	3	17
2.1.41.0.0	Bagasse[b]	22	0	2	2	2
2.1.42.0.0	Wood/Bark[b]	15	1.5	10	36	31

[a] Abbreviations used in the table have the following explanations:

A = Multiply by weight percent ash

S = Multiply by weight percent sulfur

X = Fuel consumed in this combustion system is small; emission is assumed to be negligible

NA = Not applicable; emissions for this combustion system were calculated as the total of emissions from the appropriate subsystems.

[b] The emission factors for coal, bagasse, and wood/bark give values in terms of pounds of pollutant per ton burned.

[c] The emission factors for oil give values in terms of pounds of pollutant per 1000 gallons of oil burned.

[d] The emission factors for gas give values in terms of pounds of pollutant per 10^6 cubic feet of gas burned.

Emissions from industrial fuel consumption are governed by the same principles as discussed in detail in the electric utility section. Combustion equipment design and operating practices are different, thus emission factors are different. Generally industrial combustion equipment is smaller and is operated less efficiently than electric utility equipment. Therefore, emissions of nitrogen oxides tend to be lower due to decreased furnace temperatures, and emissions of hydrocarbons, carbon monoxide, and organics tend to be higher due to incomplete combustion. SO_x emissions should be virtually the same for utility and industrial systems although the ratio of SO_2 to SO_3 may differ. Particulate emissions from coal are strongly affected by control equipment efficiency and application which are both lower in the industrial sector. Particulate emissions from oil in the industrial sector are estimated to be three times as high per unit of fuel as in the utility sector[28] due to the presence of unburned carbon.

Estimates of emissions of polycyclic organic matter were derived from data sources described in Section II. Although the data quality is poor, emissions of organics in the industrial sector appear to be an order of magnitude higher per unit of fuel than in the utility sector. Organic emission data should be accepted with extreme caution as the estimates are based on a limited number of tests, and the sampling procedures used were questionable.

Internal Combustion

Total nationwide emission estimates of particulates (including <3 micron diameter particulates), sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, and trace elements are presented in Table 93. The estimates are based on the EPA-NEDS emission factors[28] listed in Table 94 and on the methods described in the notes following Table 93.

Table 93. FLUE GAS EMISSIONS FROM INDUSTRIAL INTERNAL COMBUSTION

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[g] tons/yr		
		Total	$<3\mu$[f]	SO_x	NO_x	HC	CO	BSO	POM	BaP
2.0.00.0.0	**Industrial Generation**	2,000	200	3,200	2,700	80	160	25,000	20	5
2.2.00.0.0	Internal Combustion[b]	5.4		7.2	1,100	4.2	11			
2.2.20.0.0	Petroleum[c]	5.4		6.8	64	4.2	11			
2.2.30.0.0	Gas[d]			0.42	1,070					
2.3.00.0.0	Internal Combustion/ Gas Turbine	1.7		3.5	260					
2.3.20.0.0	Petroleum[c]	1.7		3.2	12					
2.3.21.0.0	Residual Oil[e]									
2.3.22.0.0	Distillate Oil	1.7		3.2	12					
2.3.30.0.0	Gas			0.25	250					
2.4.00.0.0	Internal Combustion/ Reciprocating Engine	3.7		3.8	870	4.2	11			
2.4.20.0.0	Petroleum[c]	3.7		3.6	52	4.2	11			
2.4.22.0.0	Distillate Oil	3.7		3.6	52	4.2	11			
2.4.30.0.0	Gas			0.17	820					

Table 93 (continued). FLUE GAS EMISSIONS FROM INDUSTRIAL INTERNAL COMBUSTION

		Trace elements,[h] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
2.0.00.0.0	Industrial Generation	5.8	260	490	25	9.1	490	870	67	93,000	200
2.2.00.0.0	Internal Combustion[b]		0.069					4.4			
2.2.20.0.0	Petroleum[c]		0.069	ND				4.4	ND		
2.2.30.0.0	Gas[d]										
2.3.00.0.0	Internal Combustion/ Gas Turbine		0.033					2.1			
2.3.20.0.0	Petroleum[c]		0.033					2.1			
2.3.21.0.0	Residual Oil[e]	0	0	0	0	0	0	0	0	0	0
2.3.22.0.0	Distillate Oil	ND	0.033	ND				2.1	ND		ND
2.3.30.0.0	Gas										
2.4.00.0.0	Internal Combustion/ Reciprocating Engine		0.036					2.3			
2.4.20.0.0	Petroleum	ND	0.036	ND				2.3	ND		ND
2.4.22.0.0	Distillate Oil	ND	0.036	ND				2.3	ND		ND
2.4.30.0.0	Gas										

Table 93 (continued). FLUE GAS EMISSIONS FROM INDUSTRIAL INTERNAL COMBUSTION

		Trace elements,[h] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
2.0.00.0.0	Industrial Generation	110	460	4800	33,000	86	510	8.1	110	1,700	110
2.2.00.0.0	Internal Combustion[b]		0.035				0.007				
2.2.20.0.0	Petroleum[c]		0.035				0.057	ND		ND	ND
2.2.30.0.0	Gas[d]										
2.3.00.0.0	Internal Combustion/ Gas Turbine		0.017				0.014	0			
2.3.20.0.0	Petroleum[c]		0.017				0.014				
2.3.21.0.0	Residual Oil[e]	0	0	0	0	0		0	0	0	0
2.3.22.0.0	Distillate Oil		0.017				0.014	ND		ND	ND
2.3.30.0.0	Gas										
2.4.00.0.0	Internal Combustion/ Reciprocating Engine		0.018				0.043				
2.4.20.0.0	Petroleum[c]		0.018				0.043	ND		ND	ND
2.4.22.0.0	Distillate Oil		0.018				0.043	ND		ND	ND
2.4.30.0.0	Gas										

Table 93 (continued). FLUE GAS EMISSIONS FROM INDUSTRIAL INTERNAL COMBUSTION

		Trace elements,[h] tons/yr							
		Te	Ti	Sn	Ti	U	V	Zn	Zr
2.0.00.0.0	Industrial Generation	2.8	0.90	18	5,600	180	2,100	220	460
2.2.00.0.0	Internal Combustion[b]			2.0					
2.2.20.0.0	Petroleum[c]			2.0			ND	ND	
2.2.30.0.0	Gas[d]								
2.3.00.0.0	Internal Combustion/ Gas Turbine								
2.3.20.0.0	Petroleum[c]								
2.3.21.0.0	Residual Oil[e]	0	0	0	0	0	0	0	0
2.3.22.0.0	Distillate Oil						ND	ND	
2.3.30.0.0	Gas								
2.4.00.0.0	Internal Combustion/ Reciprocating Engine			2.0					
2.4.20.0.0	Petroleum[c]			2.0			ND	ND	
2.4.22.0.0	Distillate Oil			2.0			ND	ND	
2.4.30.0.0	Gas								

Table 93 (continued). FLUE GAS EMISSIONS FROM INDUSTRIAL INTERNAL COMBUSTION

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[a] Values in the table represent total estimated emissions to the atmosphere from stationary combustion sources in the continental United States. An entry of "ND" signifies that a trace element has not been detected when measured and an entry left blank signifies that no information is available. The emission factors used in this table are given in Table 94.

[b] Capacity based on 1971 data from reference 19.

[c] Oil consumption was based on 68 percent of 1973 fuel use by oil companies. This value was determined as the ratio of internal combustion fuel use to total fuel use by oil companies for 1971 as reported in reference 19. A heat content of 140,000 Btu/gal was assumed. A sulfur content of 0.225 percent was taken as the average of the data reported in reference 31.

[d] Natural gas consumption was based on 14 percent of 1973 industrial fuel use. This factor was determined as the ratio of industrial combustion fuel use to total industrial fuel use for 1971. A heat content of 1022 Btu/scf was assumed.

[e] Little residual oil was burned in internal combustion engines in 1973.

[f] No information was available on emissions of less than 3 micron particles.

[g] No information was available on emission factors for organics from internal combustion engines.

[h] Trace element emissions were based on consumption data and calculated trace element content of the fuels. These were multiplied to determine the total emissions of trace elements. For distillate oil, reference 40 reported concentrations for As, Br, Cu, Mn, and Sn and reported that Sb, Ba, Cd, Cr, Hg, Ni, Se, V and Zn were not detectable. Hydrocarbon gases were assumed to be free of trace elements.

Table 94. EMISSION FACTORS FOR TABLE 93

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
2.0.00.0.0	Industrial Generation	NA	NA	NA	NA	NA
2.2.00.0.0	Internal Combustion	NA	NA	NA	NA	NA
2.2.20.0.0	Petroleum[b]	NA	NA	NA	NA	NA
2.2.30.0.0	Gas[c]	NA	NA	NA	NA	NA
2.3.00.0.0	Internal Combustion/ Gas Turbine	NA	NA	NA	NA	NA
2.3.20.0.0	Petroleum	16.8	144S	118		
2.3.21.0.0	Residual Oil	X	X	X	X	X
2.3.22.0.0	Distillate Oil	16.8	144S	118		
2.3.30.0.0	Gas		0.6	598		
2.4.00.0.0	Internal Combustion/ Reciprocating Engine	NA	NA	NA	NA	NA
2.4.20.0.0	Petroleum	33.5	144S	469	37.5	102
2.4.22.0.0	Distillate Oil	33.5	144S	469	37.5	102
2.4.30.0.0	Gas		0.6	3000		

[a] Abbreviations used in the table have the following meanings:

S = Multiply by weight percent sulfur

X = Fuel consumed in this combustion system is small; emission is assumed to be negligible

NA = Not applicable. Emissions for this combustion system were calculated as the total of emissions from the appropriate subsystems

[b] The emission factors for oil give values in terms of pounds of pollutant per 1000 gallons of oil burned.

[c] The emission factors for gas give values in terms of pounds of pollutant per 10^6 cubic feet of gas burned.

Industrial internal combustion sources account for 0.02 percent of total particulates, 0.02 percent of sulfur oxides, 4.6 percent of nitrogen oxides, 0.01 percent of hydrocarbons, and 0.007 percent of carbon monoxide emissions from all man-made sources. They account for 0.08 percent of total particulates, 0.03 percent of sulfur oxides, 10 percent of nitrogen oxides, 1.0 percent of hydrocarbons, and 1.0 percent of carbon monoxide emissions from stationary combustion sources.

NO_x is the primary pollutant resulting from internal combustion engines, as noted by McGowin[19] and Bartz et al.[44] in recent emission tests of internal combustion engines, both reciprocating and gas turbines. They confirmed that NO_x emissions from reciprocating engines are much higher than those from gas turbines.

To obtain state emission estimates for purposes of assigning priorities to the various combustion systems, it was necessary to prorate the nationwide values by multiplying by the ratio of the fuel consumption in a state to the fuel consumption nationwide. Fuel consumption estimates by state are provided in Appendix B. Additional data on trace element content are provided in Appendix C.

ASH HANDLING EMISSIONS

Ash handling air, water, and solid waste effluents created by industrial combustion systems are a coal-related problem. Coal represents 16 percent of fossil fuel consumption for industrial steam generated by external combustion. Industrial boilers burning coal, however, are responsible for approximately 99 percent of the total ash handling emissions of industrial combustion sources. Natural gas is essentially ash free and residual oil has an ash content only 1 to 2 percent of the ash content of coal. Since petroleum use, largely residual oil, constitutes only 20 percent of industrial fuel consumption; the associated ash handling waste volume is insignificant relative to coal-generated ash.

Ash Generated

The extent of control used for fly ash collection will affect the total amount of ash recovered in industrial combustion systems. Estimates of the extent of control applied to industrial sources less than 500 x 10^6 Btu/hr capacity were made by Monsanto Research Corporation, as shown below:

Capacity, 10^6 Btu/hr	Percentage of control application
10 - 200	21.0
200 - 500	53.7
> 500	70.0

The estimate of 70 percent control applied to the >500 x 10^6 Btu/hr capacity boiler systems is based on figures developed by Midwest Research Institute for all industrial boilers.[8] Oil- and gas-fired boilers are assumed to have no fly ash control although the NEDS data report 11 percent control for oil-fired boilers.

The distribution of ash between bottom ash and fly ash produced by industrial coal-fired bioler systems also influences the quantity of emissions from ash handling. The ratio of bottom ash to fly ash is estimated to be equal to the utility distribution as follows:

Type of boiler	Bottom ash/fly ash
Pulverized dry bottom	15/85
Pulverized wet bottom	35/65
Cyclone	90/10
Stokers	65/35

Coal consumption distribution within different ranges of industrial capacity was also considered. An estimated 70 percent of capacity is below 500 x 10^6 Btu/hr. The remaining 30 percent is above this value and consists of only 300 boilers.[22]

Total ash collected, calculated from the above data and assumptions, was 5.1×10^6 tons/yr in 1973 as shown in Table 95. This total is comprised of 57 percent bottom ash and 43 percent fly ash. The amount of fly ash generated is 4,800,000 tons, with 46 percent estimated to be collected.

Wastewater Emissions

The ash handling practices of industrial fuel combustion sources are subject to a great deal of uncertainty. The ash handling practices of large industrial boilers ($>500 \times 10^6$ Btu/hr) are assumed to parallel the practices followed by electric utilities. In estimating wastewater emissions, we have further assumed that all of the ash produced by smaller boilers is handled dry rather than water-sluiced and ponded. Based on the above assumptions, the amount of ash handling waste water discharged is 7100×10^6 gallons per year as shown in Table 95. This volume consists of 3800×10^6 gallons per year of fly ash handling waste water and 3300×10^6 gallons per year of bottom ash handling waste water. The change in distribution from the utility sector is due to the larger portion of bottom ash handled and disposed of dry.

The pollutants discharged with ash handling waste water are identical to those associated with electric utility ash handling, as previously shown in Table 47. Estimates of trace elements in industrial bottom and fly ash combined are included in Appendix C.

Air Emissions

Ash discharge to air results from wind erosion at landfill sites and from dry ash collection and transport. Particulate emission figures shown in Table 95 are based on an emission factor of 1 lb/ton/year applied to the total amount of ash collected which is 5,100,000 tons. This factor is identical to that used for utility combustion sources and is based on the same considerations.

Table 95. ASH HANDLING EMISSIONS: INDUSTRIAL COMBUSTION, 1973

		Ash collected, 10^3 tons/yr	Discharge water, 10^6 gallons/yr	Air emissions, 10^3 lbs of particulates/yr
2.0.00.0.0	Industrial	5,100	7,100	7,100
2.1.00.0.0	External Combustion	5,100	7,100	5,100
2.1.10.0.0	Coal	5,100	7,100	5,100
2.1.11.0.0	Bituminous	4,750	6,750	4,850
2.1.11.1.0	Pulverized Dry	2,350	3,210	2,350
2.1.11.2.0	Pulverized Wet	500	680	500
2.1.11.3.0	Cyclone	150	200	150
2.1.11.4.0	All Stokers	1,950	2,660	1,950
2.1.11.5.0	Overfeed Stokers	120	160	120
2.1.11.6.0	Spreader Stokers	1,750	2,390	1,750
2.1.11.7.0	Underfeed Stokers	80	110	80
2.1.12.0.0	Anthracite	25	34	25
2.1.12.1.0	Pulverized Dry	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0
2.1.12.4.0	All Stokers	25	34	25
2.1.13.0.0	Lignite	225	310	225
2.1.13.1.0	Pulverized Dry	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0
2.1.13.4.0	All Stokers	225	310	225
2.1.13.5.0	Overfeed Stokers	0	0	0
2.1.13.6.0	Spreader Stokers	225	310	225
2.1.13.7.0	Underfeed Stokers	0	0	0
2.1.20.0.0	Petroleum	NA[a]	NA	NA
2.1.21.0.0	Residual Oil			
2.1.21.0.1	Tangential Firing			
2.1.21.0.2	All Other			
2.1.22.0.0	Distillate Oil			
2.1.22.0.1	Tangential Firing			
2.1.22.0.2	All Other			
2.1.30.0.0	Gas	NA	NA	NA
2.1.30.0.1	Tangential Firing			
2.1.30.0.2	All Other			
2.1.41.0.0	Bagasse			
2.1.42.0.0	Wood/Bark			

[a] NA - Not applicable.

COOLING SYSTEM WATER WASTES

Cooling practices of the industrial combustion sector are very difficult to define. However, it is assumed that conventions and procedures existing in electric utilities are applicable. As such, industrial boiler systems use once-through and recirculative cooling systems. The latter system type is comprised of cooling towers, spray ponds, or combinations. The water pollutants emitted from industrial steam generation cooling systems have been assumed to be the same as those discharged from electric utility cooling systems, including: chlorine; and salts associated with calcium, magnesium, sodium, phosphorus, and chromium. Excess concentrations of these effluent water constituents result from evaporation of circulating cooling water and cooling water treatment to prevent scale deposition, corrosion, and growth of micro-organisms. The pollutants are discharged continuously in once-through systems and periodically during blowdown in recirculative systems. Table 96 presents chemical characteristics of water in industrial cooling towers.[45]

Table 97 illustrates general cooling system wastewater characteristics associated with industrial steam generation. All quantities are based on electric utility cooling water quality. Heat discharge and water withdrawal and discharge figures were derived in accordance with an estimate that 80 percent of national thermal discharge is the result of electric generation.[46] It is assumed that the heat discharge per pound of water is the same in the utility and industrial sectors.

OTHER WASTEWATER SOURCES

The strength and volume of wastewater effluent from industrial steam generation systems are influenced by a variety of factors. In general, these determinants combine to decrease the ambient impact of waste water produced in the industrial sector relative to electric utilities. However, since 50 percent of industrial boiler capacity is greater than

Table 96. INDUSTRIAL COOLING TOWER WATER QUALITY[45]

Cooling tower sampled	Ammonia		Nitrate		Total phosphorus		Zinc		Copper		Chromium		Mercury	
	Makeup, mg N/ℓ	Blowdown, mg N/ℓ	Makeup, mg N/ℓ	Blowdown, mg N/ℓ	Makeup, mg/ℓ	Blowdown, mg/ℓ	Makeup, μg/ℓ	Blowdown, μg/ℓ	Makeup, μg/ℓ	Blowdown, μg/ℓ	Makeup, μg/ℓ	Blow-down, μg/ℓ	Makeup, μg/ℓ	Blowdown, μg/ℓ
1	0.14[a] (9)[b]	0.97 (11)	0.37 (10)	2.30 (11)	0.17 (10)	4.18 (11)	34 (9)	2,107 (10)	7 (9)	1,080[d] (10)	7 (5)	9[e] (3)	3.0 (9)	6.0 (10)
2	0.08 (7)	0.10 (8)	2.32 (7)	5.24 (8)	0.04 (6)	2.41 (8)	2.7 (6)	8.5 (8)	22 (6)	13 (8)	<10 (5)	10 (2)	6.8 (6)	19.9 (8)
3	0.07 (5)	0.24 (7)	0.32 (6)	0.52 (7)	0.10 (6)	1.05 (7)	752 (6)	4,315 (7)	16 (6)	204[d] (7)	<1 (6)	7 (5)	1.8 (6)	2.4 (7)
4	0.09 (3)	0.09 (4)	0.29 (3)	1.38 (4)	0.16 (3)	0.58 (4)	1,713 (3)	4,263 (4)	23 (3)	139 (4)	<20 (1)	370 (4)	2.0 (3)	3.3 (4)
5[c]	0.12 (4)	0.48 (4)	0.60 (4)	1.05 (4)	0.09 (3)	1.69 (3)	42 (4)	2,087 (4)	3.1 (4)	545[d] (5)	<10 (4)	<10 (4)	3.9 (4)	2.7 (4)

[a] Mean concentrations. mg N = milligrams of nitrogen.

[b] Parenthesized values are number of samples.

[c] Tower 5 is Tower 1 with different chemical conditioning program.

[d] The high values are the result of extensive corrosion of copper tubing in the systems.

[e] Values may be much higher for towers using chromate for corrosion inhibition.

Table 97. INDUSTRIAL COOLING SYSTEM WASTE WATER

		Heat discharge, Btu/yr × 10^{12}		Cooling water withdrawal rate, ft^3/s					Cooling water discharge rate, ft^3/s					Chlorine discharge, ppm
		Once-through fresh	Once-through saline	Once-through fresh	Once-through saline	Cooling ponds	Cooling towers	Combined systems	Once-through fresh	Once-through saline	Cooling ponds	Cooling towers	Combined systems	All systems
2.0.00.0.0	**Industrial Generation**													
2.1.00.0.0	**External Combustion**	1,070	500	35,000	17,000	1,900	210	4,140	34,900	17,000	1,360	70	3,950	0.1-5.0
2.1.10.0.0	Coal	172	61	5,600	2,700	310	34	610	5,600	2,700	250	11	540	0.1-5.0
2.1.11.0.0	Bituminous	166	78	5,400	2,600	290	33	665	5,400	2,600	240	11	615	
2.1.11.1.0	Pulverized Dry													
2.1.11.2.0	Pulverized Wet													
2.1.11.3.0	Cyclone													
2.1.11.4.0	All Stokers													
2.1.11.5.0	Overfeed Stokers													
2.1.11.6.0	Spreader Stokers													
2.1.11.7.0	Underfeed Stokers													
2.1.12.0.0	Anthracite	1	1	40	20	2		5	40	20	2		5	
2.1.12.1.0	Pulverized Dry													
2.1.12.2.0	Pulverized Wet													
2.1.12.4.0	All Stokers													
2.1.13.0.0	Lignite	5	2	160	80	8	1	20	160	80	8		20	
2.1.13.1.0	Pulverized Dry													
2.1.13.2.0	Pulverized Wet													
2.1.13.4.0	All Stokers													
2.1.13.5.0	Overfeed Stokers													
2.1.13.6.0	Spreader Stokers													
2.1.13.7.0	Underfeed Stokers													
2.1.20.0.0	Petroleum	215	100	7,100	3,400	380	42	830	6,900	3,400	310	14	750	0.1-5.0
2.1.21.0.0	Residual Oil	160	27	5,400	5,400	280	32	620	5,150	2,560	230	10	590	
2.1.21.0.1	Tangential Firing													
2.1.21.0.2	All Other													
2.1.22.0.0	Distillate Oil	55	23	1,600	840	100	11	210	1,750	840	80	4	200	
2.1.22.0.1	Tangential Firing													
2.1.22.0.2	All Other													
2.1.30.0.0	Gas	650	305	21,400	10,400	1,140	125	2,340	21,300	10,400	950	43	2,420	0.1-5.0
2.1.30.0.1	Tangential Firing													
2.1.30.0.2	All Other													
2.1.41.0.0	Bagasse	2	1	70	34	4		8	70	34	3		6	
2.1.42.0.0	Wood/Bark	30	14	980	480	53	6	120	980	480	44	7	110	

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100×10^6 Btu/hr, it is assumed that many industry practices will be similar to the utility industry. Steam condensation and recycling must be utilized to limit water consumption and treatment.

Natural gas constitutes 61 percent of industrial external combustion fuel use and only 21 percent of electric utility fuel use (see Tables 11 and 87). This trend lessens the water pollution problem associated with industrial combustion because gas is the cleanest fossil fuel. The amount of waste water from industrial equipment cleaning, fuel handling and ash handling is reduced significantly.

Industrial boilers operate at lower temperatures and pressure than utility boilers. Therefore, industrial boiler feedwater specifications and feedwater treatment requirements are more lenient than those necessary in the utility sector. However, industrial wastewater quantity and quality are not well investigated or documented fields of study. A thorough review of NPDES permits would potentially provide significant data, but such an investigation is outside the scope of this study. Therefore, the quantitative data presented in this section are the result of proportioning characteristics of utility steam generation waste water. Consequently, the wastewater volume estimates provided in subsequent subsections are highly conservative. The industrial wastewater streams are the same types as those existing in electric utilities and result from boiler feedwater treatment, boiler blowdown, equipment cleaning, cooling, and ash handling, as previously discussed, and fuel handling as discussed in a later section.

Boiler Feedwater Treatment

The processes used for boiler feedwater treatment include clarification, softening, filtration, evaporation, demineralization, and reverse osmosis. Because industrial boilers operate at lower temperature and pressure than utility boilers, scale forming constituents such as silica, iron, and calcium and magnesium ions remain water soluble at higher concentrations. The degree of solids removal required is reduced to the point where trace quantity removal systems such as evaporation and reverse osmosis are used only to a slight extent. Therefore, the dominant treatment methods are clarification, softening, and filtration.

Investigation into appropriate operating practice for modern industrial boilers is currently being undertaken by the ASME Research Committee on Water in Thermal Power Systems.[47] The study will present a consensus of recommended industrial boiler feedwater quality guidelines. The preliminary figures for alkalinity in low pressure boilers (<1000 psi) are based on a long established guideline of the ABMA.[48] This requires that alkalinity remain less than or equal to 20 percent of total dissolved solids and less than or equal to 10 percent of unadjusted conductivity. This specification effectively controls alkalinity as a carryover mediator but does not protect against corrosion at higher pressures. Therefore, the ASME Research Committee is tentatively advising that, at pressure greater than 1000 psi, the free sodium or potassium hydroxide alkalinity be equal to zero.

References 47, 48, and 49 recommend the industrial boiler feedwater characteristics that appear in Table 98. The values presented for iron, copper, and hardness are preliminary and subject to verification in the very near future. Recommendations for low pressure boilers are controversial in that operators of these units claim that the requirements are unnecessarily stringent. However, if these guidelines are not followed, the extent of blowdown can increase causing a large loss of heated water and inefficient use of fuel as well as increased heat discharge to receiving water.

Table 99 illustrates the boiler feedwater treatment wastewater volumes calculated for industrial external combustion steam generation. The values are based entirely on figures obtained for electric utilities and

Table 98. INDUSTRIAL BOILER FEEDWATER SPECIFICATIONS[47,48,49]

Pressure at outlet of steam drum, psig	Total solids, ppm	Total alkalinity, ppm	Suspended solids, ppm	Oils, fats, grease and other organics, ppm	Silica, ppm	Iron,[a] ppm	Copper,[a] ppm	Hardness,[a] ppm $CaCO_3$
0-50	2500	500	150	10	-	-	-	-
51-300	3500	700	300	10	125	0.100	0.050	0.300
301-450	3000	600	250	-	90	0.050	0.025	0.300
451-600	2500	500	150	-	50	0.030	0.020	0.200
601-750	2000	400	100	-	35	0.025	0.020	0.200
751-900	1500	300	60	-	20	0.020	0.015	0.100
901-1000	1250	250	40	-	8	0.020	0.015	0.050
1001-1500	1000	200	20	-	2.5	0.010	0.010	0.0
1501-2000	750	150	10	-	1.0	0.010	0.010	0.0
> 2000	500	100	5	-	0.5	-	-	-

[a] Preliminary recommendations.

Table 99. INDUSTRIAL BOILER FEEDWATER TREATMENT WASTES, 1973

		Volume, 10^6 gal/yr	Volume, m^3/day	TSS, ppm
2.0.00.0.0	Industrial			
2.1.00.0.0	External Combustion	5,050	52,370	10-25
2.1.10.0.0	Coal	810	8,400	
2.1.11.0.0	Bituminous	780	8,290	
2.1.11.1.0	Pulverized Dry	385	3,990	
2.1.11.2.0	Pulverized Wet	75	780	
2.1.11.3.0	Cyclone	25	260	
2.1.11.4.0	All stokers	295	3,060	
2.1.11.5.0	Overfeed Stokers	20	210	
2.1.11.6.0	Spreader Stokers	265	2,750	
2.1.11.7.0	Underfeed Stokers	10	100	
2.1.12.0.0	Anthracite	6	60	
2.1.12.1.0	Pulverized Dry			
2.1.12.2.0	Pulverized Wet			
2.1.12.4.0	All Stokers	6	60	
2.1.13.0.0	Lignite	24	250	
2.1.13.1.0	Pulverized Dry			
2.1.13.2.0	Pulverized Wet			
2.1.13.4.0	All Stokers	24	250	
2.1.13.5.0	Overfeed Stokers			
2.1.13.6.0	Spreader Stokers	24	250	
2.1.13.7.0	Underfeed Stokers			
2.1.20.0.0	Petroleum	1,010	10,470	
2.1.21.0.0	Residual Oil	755	7,830	
2.1.21.0.1	Tangential Firing	120	1,245	
2.1.21.0.2	All Other	635	6,585	
2.1.22.0.0	Distillate Oil	255	2,645	
2.1.22.0.1	Tangential Firing	40	415	
2.1.22.0.2	All Other	215	2,230	
2.1.30.0.0	Gas	3,080	31,940	
2.1.30.0.1	Tangential Firing	310	3,215	
2.1.30.0.2	All Other	2,770	28,725	
2.1.41.0.0	Bagasse	10	120	
2.1.42.0.0	Wood/Bark	140	1,440	

are computed according to actual utility and industrial fuel use in 1973. The effluent quantities reported could be reduced further if feedwater solids concentration specifications for utility and industrial boilers were also considered. However, such figures would be over-refined considering the precision of the data input. Therefore, the figures presented are very conservative and represent the highest possible flow volume.

The total solids or suspended solids concentration of feedwater treatment waste water is equally difficult to determine. The range illustrated in Table 99 is based on the concentration stipulated for clarification wastes from electric utilities and the assumption that effluent concentration will be reduced since the average industrial feedwater specifications are liberalized to a large extent.

Boiler Blowdown

Boiler blowdown is practiced in industrial boilers in the same manner as electric utility boilers. Blowdown is required to limit the concentration of dissolved and suspended solids in the boiler water. This practice helps prevent the formation of scale on metal surfaces which otherwise causes reduced heat transfer efficiency and deteriorated structural stability. The hazardous constituents found in blowdown include suspended and dissolved solids, hardness, acidity, alkalinity, phosphates, and silica. All concentrations will be greater than or equal to those characteristic of utility boiler blowdown due to the less stringent water specifications for industrial boilers.

There are no data that specifically define the volume and characteristics of industrial boiler blowdown other than the NPDES permit applications.[50] As such, the figures presented for industrial boilers in Table 100 are based on electric utility boiler blowdown quantity and quality. The blowdown volume reported is proportional to utility and industrial fuel

Table 100. INDUSTRIAL BOILER BLOWDOWN, 1973

		Volume, 10^6 gal/yr	TSS, mg/ℓ	TDS, mg/ℓ	Ammonia, mg/ℓ	Phosphate, mg/ℓ	Alkalinity, mg/ℓ
2.0.00.0.0	Industrial						
2.1.00.0.0	External Combustion	3,630	30	150	1	5-50	10-100
2.1.10.0.0	Coal	585					
2.1.11.0.0	Bituminous	560					
2.1.11.1.0	Pulverized Dry	280					
2.1.11.2.0	Pulverized Wet	55					
2.1.11.3.0	Cyclone	17					
2.1.11.4.0	All Stokers	210					
2.1.11.5.0	Overfeed Stokers	13					
2.1.11.6.0	Spreader Stokers	190					
2.1.11.7.0	Underfeed Stokers	9					
2.1.12.0.0	Anthracite	4					
2.1.12.1.0	Pulverized Dry	0					
2.1.12.2.0	Pulverized Wet	0					
2.1.12.4.0	All Stokers	4					
2.1.13.0.0	Lignite	17					
2.1.13.1.0	Pulverized Dry	0					
2.1.13.2.0	Pulverized Wet	0					
2.1.13.4.0	All Stokers	17					
2.1.13.5.0	Overfeed Stokers	0					
2.1.13.6.0	Spreader Stokers	17					
2.1.13.7.0	Underfeed Stokers	0					
2.1.20.0.0	Petroleum	720					
2.1.21.0.0	Residual Oil	540					
2.1.21.0.1	Tangential Firing	85					
2.1.21.0.2	All Other	455					
2.1.22.0.0	Distillate Oil	180					
2.1.22.0.1	Tangential Firing	30					
2.1.22.0.2	All Other	150					
2.1.30.0.0	Gas	2,215					
2.1.30.0.1	Tangential Firing	215					
2.1.30.0.2	All Other	1,900					
2.1.41.0.0	Bagasse	10					
2.1.42.0.0	Wood/Bark	100					

consumption. Other values are equal to those presented for electric utilities. Although the data quality is questionable, these quantities represent the best available data.

Equipment Cleaning Wastes

Industrial steam generating boilers require periodic cleaning in the same manner as utility boilers. The water side of industrial boilers requires preoperational and operational cleaning. The extent and characteristics of water-side cleaning wastes are independent of the type of fuel used. Cleaning waste waters can contain excess acidity, alkalinity, phosphates, organic compounds, copper, iron, hardness, and turbidity. Fire-side boiler cleaning is also required in the industrial steam generation sector. The quantity of water and waste is vastly reduced from utility generation due to the large use of natural gas for fuel. As such, the quantity and impact of boiler fire-side cleaning waste water is insignificant.

Cleaning waste water disposal methods include controlled periodic release to a waterway and discharge to a holding tank prior to discharge to ambient water. As in utility boiler cleaning, federal regulations[51] prohibit controlled release without a permit so that holding and sedimentation is the predominant control method. Where cleaning is done by an outside firm, waste water may be trucked away to appropriate land disposal.

The characteristics of equipment cleaning waste water appear in Table 101. The volume is derived from the amount associated with electric generation utility boilers and is based on the proportion of fuel consumption within each sector. Pollutant concentrations existing in electric utility cleaning waste water are reported for industrial cleaning waste water and, therefore, represent a very conservative estimate of emissions. However, these values are currently the best available data to adapt for industrial boiler cleaning.

Table 101. INDUSTRIAL EQUIPMENT CLEANING WASTE WATER, 1973

		Volume, 10^6 gal/yr	Hardness, mg/ℓ	TS, mg/ℓ	TSS, mg/ℓ	TDS, mg/ℓ
2.0.00.0.0	Industrial					
2.1.00.0.0	External Combustion	1,210	4,000	9,130	130	9,000
2.1.10.0.0	Coal	195				
2.1.11.0.0	Bituminous	187				
2.1.11.1.0	Pulverized Dry	92				
2.1.11.2.0	Pulverized Wet	18				
2.1.11.3.0	Cyclone	6				
2.1.11.4.0	All Stokers	71				
2.1.11.5.0	Overfeed Stokers	4				
2.1.11.6.0	Spreader Stokers	64				
2.1.11.7.0	Underfeed Stokers	3				
2.1.12.0.0	Anthracite	2				
2.1.12.1.0	Pulverized Dry	0				
2.1.12.2.0	All Stokers	2				
2.1.13.0.0	Lignite	6				
2.1.13.1.0	Pulverized Dry	0				
2.1.13.2.0	Pulverized Wet	0				
2.1.13.4.0	All Stokers	6				
2.1.13.5.0	Overfeed Stokers	0				
2.1.13.6.0	Spreader Stokers	6				
2.1.13.7.0	Underfeed Stokers	0				
2.1.20.0.0	Petroleum	240				
2.1.21.0.0	Residual Oil	180				
2.1.21.0.1	Tangential Firing	28				
2.1.21.0.2	All Other	152				
2.1.22.0.0	Distillate Oil	60				
2.1.22.0.1	Tangential Firing	10				
2.1.22.0.2	All Other	50				
2.1.30.0.0	Gas	740				
2.1.30.0.1	Tangential Firing	74				
2.1.30.0.2	All Other	666				
2.1.41.0.0	Bagasse	5				
2.1.42.0.0	Wood/Bark	30				

FUEL STORAGE AND HANDLING

Coal use represents 16 percent of fossil fuel consumption by the industrial combustion boilers considered in this document. Industrial boilers burning coal are responsible for all fuel handling wastes. Emissions from industrial petroleum and natural gas storage are negligible. Industrial coal handling practices do not differ appreciably from methods followed by electric utilities. However, the industrial sector does not require storage facilities as extensive as electric utilities require. A storage capacity of 10 to 30 days' coal supply is recommended.[52] Storage requirements shown in Table 102 were calculated on the basis of a 30-day storage requirement, 15-feet storage depth, and a density of 75 lb/cubic foot.

Wastewater Emissions

The volume of coal pile drainage shown in Table 102 was determined for a 40-inch average yearly rainfall. The concentration of individual pollutants in the coal drainage will be equal to figures previously presented in Table 69 for utility coal handling. This is the case because the relative mix of bituminous, anthracite, and lignite coal consumption in both the utility and industrial sectors is the same.

The extent of coal drainage collection and treatment within the industrial sector is unknown. It is assumed that industrial boilers of greater than 500×10^6 Btu/hr capacity have collection and treatment corresponding to utility practices. This accounts for 25 percent of industrial steam generation capacity using coal for fuel.

Air Emissions

Air emissions from industrial coal pile storage and handling, shown in Table 102, were calculated in the same manner as for utilities. A factor

Table 102. INDUSTRIAL COAL HANDLING EMISSIONS, 1973

		Storage requirements			Water emissions	Air emissions
		10^3 tons stored	Land area required, acres	Volume required, acre-ft	Coal drainage, gal/yr × 10^6	10^3 lbs of particulates/yr
2.0.00.0.0	Industrial					
2.1.00.0.0	External Combustion	5,000	200	3,000	220	18
2.1.10.0.0	Coal	5,000	200	3,000	220	18
2.1.11.0.0	Bituminous	4,700	190	2,950	210	17
2.1.11.1.0	Pulverized Dry	2,300	95	1,400	105	8.6
2.1.11.2.0	Pulverized Wet	4,500	19	280	20	1.6
2.1.11.3.0	Cyclone	150	6	90	5	0.4
2.1.11.4.0	All Stokers	1,800	70	1,050	80	6.5
2.1.11.5.0	Overfeed Stokers	120	4	65	5	0.4
2.1.11.6.0	Spreader Stokers	1,600	63	970	72	5.9
2.1.11.7.0	Underfeed Stokers	80	3	45	3	0.25
2.1.12.0.0	Anthracite	50	2	30	2	0.16
2.1.12.1.0	Pulverized Dry	0	0	0	0	0
2.1.12.2.0	Pulverized Wet	0	0	0	0	0
2.1.12.4.0	All Stokers	50	2	30	2	0.16
2.1.13.0.0	Lignite	250	8	120	8	0.65
2.1.13.1.0	Pulverized Dry	0	0	0	0	0
2.1.13.2.0	Pulverized Wet	0	0	0	0	0
2.1.13.4.0	All Stokers	250	8	120	8	0.65
2.1.13.5.0	Overfeed Stokers	0	0	0	0	0
2.1.13.6.0	Spreader Stokers	250	8	120	8	0.65
2.1.13.7.0	Underfeed Stokers	0	0	0	0	0
2.1.20.0.0	Petroleum	NA[a]	NA	NA	NA	NA
2.1.21.0.0	Residual Oil					
2.1.21.0.1	Tangential Firing					
2.1.21.0.2	All Other					
2.1.22.0.0	Distillate Oil					
2.1.22.0.1	Tangential Firing					
2.1.22.0.2	All Other					
2.1.30.0.0	Gas	NA	NA	NA	NA	NA
2.1.30.0.1	Tangential Firing					
2.1.30.0.2	All Other					
2.1.41.0.0	Bagasse	NA	NA	NA	NA	NA
2.1.42.0.0	Wood/Bark	NA	NA	NA	NA	NA

[a] NA - Not applicable.

of 0.0035 lb/ton/yr[53,54] is used and is applied to a total of 5 x 10^6 ton/yr of coal stored.

SOLID WASTE COMBUSTION

In the past several years interest in the burning of waste products as fuels has increased[18] due to the high cost of disposal and scarcity of suitable landfill sites. There are currently four methods of utilizing solid wastes as fuels for the production of steam or electricity for industrial use. These are:

- The incineration of municipal refuse (MR) to provide steam for industrial purposes.
- The supplemental firing of waste fuels in industry to provide heat and/or steam.
- The firing of sugar cane wastes, bagasse, to produce steam.
- The firing of wood, bark wastes or wood products to produce heat or process steam.

Waste products are used for fuel primarily because they represent a disposal problem and are available at minimum costs. Table 103[18] contains a listing of the heating values of various waste products.

The firing of wastes to provide energy for industry is carried out on a comparatively small scale; i.e., each plant burns its own wastes for disposal and to meet part of its own energy requirements. The exception is the firing of MR as a fuel where large collection and firing facilities are an economic necessity. The small size of individual contributors to solid waste combustion makes inventorying each contributor difficult, if not impossible.

Table 103. TYPICAL INDUSTRIAL WASTES WITH SIGNIFICANT FUEL VALUE[18]

Waste	Average heating value (as fired), Btu/lb
Gases:	
Coke-oven	19,700
Blast-furnace	1,139
Refinery	21,800
Liquids:	
Industrial sludge	3,700- 4,200
Black liquor	4,400
Sulfite liquor	4,200
Dirty solvents	10,000-16,000
Spent lubricants	10,000-14,000
Paints and resins	6,000-10,000
Oily waste and residue	18,000
Solids:	
Bagasse	3,600- 6,500
Bark	4,500- 5,200
General wood wastes	4,500- 6,500
Sawdust and shavings	4,500- 7,500
Coffee grounds	4,900- 6,500
Nut hulls	7,700
Rice hulls	5,200- 6,500
Corn cobs	8,000- 8,300

For clarity, each method of solid waste firing for industrial purposes will be discussed separately.

Bagasse Combustion

Bagasse is the fibrous waste produced from the processing of sugar cane. It has an average heat content of 4,600 Btu per pound,[24] and has been burned to provide energy for electric power generation in Hawaii since shortly after the turn of the century. Generally, every cane sugar factory produces power for its own use and some supplemental power. The power output ranges from 2.3 to 17.0 MW.[25] Stack gas emissions have not been studied to any great extent although the EPA is now conducting tests in Hawaii and Florida to determine emission factors for bagasse combustion.

However, because of the low sulfur content of bagasse, SO_2 emissions should be low. NO_x levels are expected to be small because of the low flame temperatures. The major pollutant loading comes from particulate emissions. The variations in the properties of the bagasse fuel and boiler design result in large fluctuations in the level of emissions (1.8 – 20.0 mg/m^3)[24] and corresponding changes in particle size distribution of the fly ash. The fly ash is usually returned to the field for cultivation.

Table 104 lists the emissions from bagasse burning facilities.[3] The emissions for bagasse were taken from the 1972 NEDS Report because of the lack of information from any other sources.

Table 104. TOTAL STACK EMISSIONS FROM BAGASSE BURNING FACILITIES[3]

	Tons fuel	10^{12} Btu/yr	Emissions, 10^3 tons/yr				
			Particulates	SO_2	NO_x	CO	HC
1.2.4.1 Bagasse	–	–	42	0	5.5	5.5	5.5

The Incineration of Municipal Refuse

Facilities for the disposal of solid waste and the production of process steam are more numerous than for the production of electricity. Table 105 lists the facilities presently in operation or planned for the near future that plan to use MR fuel combustion to generate steam for distribution. The chemical and physical properties of municipal refuse have been documented in Section II. As noted, the heating value of MR is too low and variable for utility use.

The steam generating plant in Saugus, Mass., will be discussed below as a general example of industrial steam generation from wastes. The Saugus plant[56] utilizes a water wall boiler. The basic requirements of the plant are to accept an average of 1200 tons per day of domestic and

Table 105. PLANNED OR EXISTING REFUSE TO ENERGY SYSTEMS[55]

Location	Number of boilers	Refuse feed rate, ton/hr	Steam rate, lb/hr	Steam temp., °F	Steam pressure, psig	Steam use	Refuse preparation[a]			Other fuel	Furnace type	Emission control system	Status[b]
							A.C.	S.	M.				
Saugus, Mass.	2	62.5	370,000	875	890	Commercial - G. E.	0	X	X	Oil	Moving grate	E.S.P.	UC 1975
Braintree, Mass	2	10	60,000	~405	250		0	0	0	Gas	Traveling grate	E.S.P.	OP 1971
Harrisburg, Pa.	2	30	185,000	465	250		0	X	X	Oil	Reciprocating grate	E.S.P.	OP 1972
Chicago, Ill.	4	66.67	446,000	414	275		0	X	0	Gas	Grate	E.S.P.	OP 1970
Nashville, Tenn.	2	30	270,000	600	400	Commercial (heating and cooling)	0	0	0		Moving grate	Wet scrubber	OP 1974
Norfolk, Va.	3	15	100,000	~425	275	U.S. Navy Ships	0	X	0		Reciprocating grate	E.S.P. and Multi-cyclone	OP 1967
Portsmouth, Va.	2	6.67	60,000	~340	115					Oil	Grate		UC 1975
Akron, Ohio													DSC
Cleveland, Ohio													FSC
Palmer Township, Pa.													FSC
Brockton, Mass.													SS
Chicago, Ill.													UC
Bridgeport, Conn.													C Awd.
Hempstead, N.Y.													C Awd.
New Britain, Conn.													C Neg.
Lane County, Ore.													PDC
Hackensack Meadowlands, N.J.													FSC
Milwaukee, Wisc.													FSC
Washington, D.C.													US
Montgomery County, Md.													US
Madison, Wisc.													US
Los Angeles, Calif.													US
Honolulu, Hawaii													US
Housatonic Valley, Conn.													US

[a] A.C. = Air Classifier
S. = Shredder
M. = Magnetic separator.

[b] UC = Under Construction
OP = Operating
DSC = Design Study Complete
FSC = Feasibility Study Complete
SS = System Shakedown in progress
C Awd. = Contract Awarded
C Neg. = Contract under Negotiation
PDC = Preliminary Design Complete
US = Under Study.

commercial refuse and to provide steam at 652 psig and 785°F to 825°F to a nearby General Electric Plant. Operation is 7 days/week and 24 hours/day with a minimum of 2 billion pounds of steam to be delivered annually. Refuse is burned on a Wheelabrator/Von Roll moving grate system. Combustion temperatures are in the range 1000 to 1800°F. Cooled reaction gases pass through two Wheelabrator-Lurgi electrostatic precipitators which are designed to reduce particulate emissions to 0.025 grains/scf. Fly ash is passed through a magnetic separator and sent to landfills. Quench water is discharged in wet ash or evaporated. Blowdown water is almost entirely consumed by transferring it to quench tanks.

There is not, as yet, any specific information on air emissions for waste to energy facilities. However, there is roughly a 1 to 1 correspondence between the emissions from incineration only and waste to energy incineration processes.[57] Consequently, although air emissions from waste to energy facilities are not known, they can be deduced from the known properties for normal incineration facilities. Tables 106[58] and 107[59] list the air emissions to be expected from waste to energy steam-producing facilities. Because refuse is a low sulfur fuel, typically of ~0.1 percent sulfur content, no SO_2 scrubbing is performed on the stack gases. NO_x emissions are expected to be below 0.5 pounds per 10^6 Btu heat input.[57] Table 107 demonstrates the change in trace element emissions to be expected from the use of different control equipment. Using the emission factors of Tables 106 and 107, pollutant loadings from the firing of MR for the production of steam for industrial purposes can be calculated, and these are given in Table 108.

The extent of potentially hazardous substances from waste to energy incineration processes has not yet been measured. Odors arising from the refuse are destroyed at the incineration temperatures used. Of special concern in waste to energy processes is the occurrence of pollutants not normally found in conventional energy generating processes. For example, the following compounds have all been found in incinerator stack gases:

Table 106. AIR EMISSIONS FROM REFUSE INCINERATORS[a],58

Pollutant	Furnace type and average capacity			
	Rocking grate, 350 tons/day	Reciprocating grate, 350 tons/day	Traveling grate, 350 tons/day	Suspension burning, 300 tons/day
1. Mineral particulate				
lb/ton of refuse	13.6	28.1	12.8	48.9
lb/ton of ash (ex. glass, **metal**)	250	517	236	900
2. Combustible particulate				
lb/ton of refuse	2.70	2.70	2.70	1.93
lb/ton of **volatile carbon**	14	14	14	10
3. Carbon monoxide				
lb/ton of refuse	20.59	20.59	20.59	14.72
4. Nitrogen oxides (as NO_2)				
lb/ton of refuse	3.53	3.53	3.53	3.44
lb/MM Btu	0.40	0.40	0.40	0.39
5. Hydrocarbons				
lb/ton of refuse	1.58	1.58	1.58	1.13
6. Polynuclear hydrocarbons				
lb/ton of refuse x 10^3	2.94	2.94	2.94	2.10
lb/ton of **volatile carbon x** 10^3	15.2	15.2	15.2	10.8
7. Sulfur oxides (as SO_2)				
lb/ton of refuse	3.94	3.94	3.94	3.94
lb/ton of sulfur **in refuse**	4000	4000	4000	4000
8. Hydrogen chloride				
lb/ton of refuse	0.99	0.99	0.99	0.99
lb/ton of PVC resin	1180	1180	1180	1180
9. Volatile metals (as lead)				
lb/ton of refuse	0.032	0.032	0.032	0.032
lb/ton of metals in refuse	0.4	0.4	0.4	0.4

[a] **Variations in composition of refuse may produce different values.**

Table 107. EMISSION FACTORS FOR MUNICIPAL INCINERATORS[59]

Element	Sample conditions	Emission factor, lb/ton refuse burned
Be	Uncontrolled After ESP	0.00003 0.00003
Cd	Uncontrolled After wet scrubber	0.003 0.0008
Mn	Uncontrolled After ESP	0.03 0.007
Hg	Uncontrolled	0.001
Ni	After wet scrubber	0.003
V	Uncontrolled	0.001
Pb	Uncontrolled	0.032

Table 108. TOTAL STACK EMISSIONS FOR BURNING MUNICIPAL REFUSE[a]

	Tons fuel[b]	10^{12} Btu/yr[c]	10^3 ton/yr				
			Particulate[d]	SO_2	NO_x	CO	HC
2.2.40.0.0 Refuse	1.88×10^6	15	1.3	3.7	3.1	17.6	1.35

	ton/year								
	Polynuclear hydrocarbons	HCl	Be	Cd	Mn	Hg	Ni	Pb	V
2.2.40.0.0 Refuse	0.003	0.93	0.03	2.82	6.58	0.94	2.82	30.08	0.94

[a] Calculated from information supplied in Tables 106 and 107.

[b] The plants included in this category are (see Table 105): Saugus, Ma.; Braintree, Ma.; Harrisburg, Pa.; Chicago, Il.; Nashville, Tn.; and Norfolk, Va.

[c] Assuming 1 pound refuse = 4000 Btu, and 8760 operating hours at capacity.

[d] Assuming 95 percent particulate removal efficiency.

formic, acetic, palmetic, stearic and oelic acids; methyl and ethyl acetate and ethyl stearate; formaldehyde and acetaldehyde; hydrocarbons; and phenols. However, incineration of municipal refuse in stationary sources is not now judged to be a significant contributor to total air hydrocarbon emissions.[57]

Water pollutants from waste to energy facilities, using the Saugus Plant as a benchmark, are expected to be minimal. This is because the water handling system is essentially self-contained with make-up water being supplied from the municipal water supply, and only small amounts of cooling water are needed for process steam systems. Leachates from the wet ash should pose the only threat to water quality. However, the use of landfill liners should alleviate any problem that may exist. Typical refuse ash composition is listed in Table 109.[60] Reductions in volume of municipal refuse by as much as 90 percent will minimize most solid waste disposal problems associated with the volume of the waste.

Table 109. AIR CLASSIFIED REFUSE ASH COMPOSITION[60]
(WEIGHT PERCENT)

	Average	Maximum	Minimum
P_2O_5	1.43	2.04	0.99
SiO_2	49.90	58.10	39.90
Al_2O_3	11.38	26.90	6.10
TiO_2	0.87	1.52	0.07
Fe_2O_3	7.89	22.19	3.03
CaO	12.21	15.80	8.51
MgO	1.29	2.32	0.22
SO_3	1.48	3.75	0.54
K_2O	1.57	2.91	0.92
Na_2O	8.82	19.20	3.11
SnO_2	0.05	0.10	0.02
CuO	0.32	1.74	0.08
ZnO	0.41	2.25	0.09
PbO	0.19	0.73	0.04

The Supplemental Firing of Industrial Wastes

At present, the only large scale practitioners of supplementary firing of liquid fuels are petroleum refineries.[61] Liquid and sludge petroleum refinery wastes are mixed with either oil or gas and fired in conventional or modified boilers mainly for process steam generation and heat. Complete inventories of the facilities utilizing the supplemental firing of industrial wastes are not available. However, an industry survey has recently been made and, while not complete, can serve as a lower limit of the pollutant loadings to be expected.[61] These pollutant loadings are listed in Table 110.[61]

Table 110. TOTAL STACK EMISSIONS FOR BURNING WASTE FUELS IN PETROLEUM REFINERIES

	Tons fuel	10^{12} Btu/yr of waste fuel	Emissions, 10^3 ton/yr				
			Particulate	SO_2	NO_x	CO	HC
2.2.43.0.0 Industrial waste[a]	NA	3.8	0.83	15.13	12.8	0.36	-

[a] All calculations based on information given in reference 61.

In interpreting the data presented in Table 110 it should be noted that the emissions reported are for burning gas or oil and the supplementary waste fuel. Generally, this mixture is ~70/30 on a heat basis.[61]

Wood Wastes as a Fuel

Pulp and paper industries are the main users of wood wastes for supplementary fuel. Secondary users of wood wastes are the logging and wood manufacturing industries that burn bark and wood wastes in specially designed boilers.[62]

Table 111 lists the stack emissions from wood wastes. The consumption of wood was calculated from the emissions reported in the 1972 NEDS Report.[3]

The consumption figure was then updated using a growth factor of 0.012 for 1975. The updated consumption data were used to calculate the emissions. The emission factors were taken from reference 28.

Table 111. TOTAL STACK EMISSIONS FOR BURNING WOOD WASTES

	Tons fuel, 10^6 ton/yr	10^{12} Btu/yr	Emissions, 10^3 ton/yr				
			Particulate	SO_2	NO_x	CO	HC
2.2.42.0.0 Wood/Bark	163	-	210	18	140	44	31

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SECTION IV

COMMERCIAL/INSTITUTIONAL COMBUSTION SOURCES

The commercial/institutional sector consists of all activities not classified as electric utility, mining, manufacturing, transportation, or residential. It includes farms, wholesale and retail trade, office buildings, hotels, restaurants, hospitals, schools, museums and government facilities.[1] Fuel consumed by the commercial/institutional sector during 1973 was used for space heating (82 percent), water heating (12 percent), cooking (3 percent), and air conditioning (3 percent). Essentially all the coal and oil was used for space heating. Natural gas was used for space heating (66 percent), water heating (23 percent), cooking (6 percent), and air conditioning (5 percent).[1] Estimated 1973 fuel consumption by the commercial/institutional sector (external combustion) is presented in Table 112: approximately 3 percent of the commercial fuel was coal while 44 percent was oil and 53 percent was gas.[2-6]

The greatest commercial/institutional application of internal combustion engines is for the pumping of municipal water and sewage. Internal combustion engines are also used commercially to power pumps, compressors, and emergency power generators.

COMBUSTION EQUIPMENT AND FUEL USAGE

Commercial/institutional combustion units range in size from 0.3×10^6 Btu/hr to units greater than 100×10^6 Btu/hr. The biggest units are used at large hospitals, office complexes, and government facilities such as military bases. Past studies have limited the term commercial to boilers in the size range 0.3 to 10 x 10^6 Btu/hr.[7,8] However, fuel use data are only available for the total commercial/institutional sector, so GCA attempted to define the emissions and boilers associated with the available fuel use data. All boilers in the size range 0.3 to 10 x 10^6 Btu/hr were assumed to be commercial boilers. The commercial/institutional boiler population in the size range above 10 x 10^6 Btu/hr was estimated from NEDS data. Since only boilers emitting more than 100 tons/year of one of the five criteria pollutants are included in the NEDS system, the minimum size of boilers included depends on the fuel used and the average yearly load factor. In practice, some smaller boilers are included, and the NEDS system covers 40 percent of the coal, 5 percent of the oil, and 8 percent of the gas burned by sources classified as commercial/institutional boilers.[9]

Table 112. COMMERCIAL/INSTITUTIONAL FOSSIL FUEL CONSUMPTION, 1973[a]

		Total - all uses, 10^{12} Btu/yr	Space heating, 10^{12} Btu/yr
3.0.00.0.0	Commercial/Institutional	5,436	4,449
3.1.10.0.0	Coal	156	156
3.1.11.0.0	Bituminous[b]	100	100
3.1.12.0.0	Anthracite[c]	55	55
3.1.13.0.0	Lignite	1	1
3.1.20.0.0	Petroleum	2,379	2,379
3.1.21.0.0	Residual oil[d]	1,269	1,269
3.1.22.0.0	Distillate oil[e]	1,110	1,110
3.1.30.0.0	Gas[f]	2,901	1,914

[a] External combustion only.

[b] 22.4 x 10^6 Btu/ton.

[c] 26.0 x 10^6 Btu/ton.

[d] 146,000 Btu/gal.

[e] 140,000 Btu/gal.

[f] Includes 8.5 percent LPG — 1,020 Btu/ft^3 (gas), 90,000 Btu/gal (liquid).

The number, capacity, and fuel consumption of the commercial boilers included in the NEDS system are summarized in Table 113. We estimated fuel use by commercial/institutional boilers as a function of size by assuming that the boilers above 10 x 10^6 Btu/hr included in the NEDS system represented all the coal-fired boilers, one-half the oil-fired boilers, and one-quarter of the gas-fired boilers (see Table 114) in that size range.

Commercial/institutional sector fuel use by combustion system category is presented in Table 115. Bituminous coal-fired commercial boilers above 10 x 10^6 Btu/hr were estimated to be 2 percent pulverized wet and 35 percent pulverized dry, based on our recent survey of NEDS data. All other bituminous coal-fired boilers are stokers. Anthracite coal is usually burned only in stokers; the high ignition temperature of anthracite does not allow the employment of spreader stokers.[10] Only a very small amount of lignite is burned by commercial users, probably in small stokers. The amount of residual oil burned in tangentially-fired boilers was calculated by assuming that boilers above 100 x 10^6 Btu/hr were similar to utility boilers. Because only a small fraction of oil utilized by the commercial/institutional sector is burned in boilers above 100 x 10^6 Btu/hr, less than 1 percent is burned in tangentially-fired units. A similar analysis of gas-fired boilers indicated that less than 4 percent of gas is burned in tangentially-fired units. The figure for wood/bark combustion represents data on file in the NEDS system and may represent only a very small fraction of the wood burned by the commercial/institutional sector. Internal combustion fuel use was estimated by updating municipal internal combustion fuel use data[11] from 1973. The fuel used is 50 percent oil — 50 percent gas.

EMISSION SOURCES

Because oil and gas are clean fuels relative to coal, and because of the small boiler sizes considered, many pollutant waste streams appear to be

Table 113. COMMERCIAL/INSTITUTIONAL BOILERS INCLUDED IN THE NEDS SYSTEM[9]

Fuel	Size, 10^6 Btu/hr	Number	Capacity, 10^6 btu/hr	Fuel consumption, 10^{12} Btu/yr
Coal	1-10	249	1,226	6.2
	10-100	355	14,186	37.9
	> 100	40	7,617	18.8
Oil	1-10	893	2,994	18.9
	10-100	779	28,080	70.8
	> 100	107	25,836	27.4
Gas	1-10	349	732	34.7
	10-100	288	7,000	38.7
	> 100	72	27,228	83.8

Table 114. ESTIMATED COMMERCIAL/INSTITUTIONAL FUEL CONSUMPTION BY BOILERS AS A FUNCTION OF SIZE

Fuel	Size, 10^6 Btu/hr	Number[a]	Capacity, 10^6 Btu/hr	Fuel consumption, 10^{12} Btu/yr
Coal	0.3-10	40,000	53,800[b]	99
	10-100	355	14,200	38
	> 100	40	7,600	19
Oil	0.3-10	882,000	1,090,000[b]	2,184
	10-100	1,560	56,000	141
	> 100	220	52,000	54
Gas	0.3-10	578,000	778,000[b]	1,431
	10-100	1,160	28,000	144
	> 100	280	108,000	339

[a] The total number of boilers in the size range 0.3-10 x 10^6 Btu/hr has been estimated as 91,000 to 3,100,000.[7] Commercial/institutional and industrial oil-fired boilers are estimated to number 1,100,000.[8] Industrial boilers represent a comparatively small number. GCA estimated 1,500,000 boilers in the range 0.3-10 x 10^6 Btu/hr. The number was distributed based on the fuel burned. Data for boilers above 10 x 10^6 Btu/hr are discussed in the text.

[b] Based on an average yearly load factor of 21 percent.[12]

Table 115. COMMERCIAL/INSTITUTIONAL FUEL USE, 1973[a]

		Fuel use, 10^{12} Btu
3.0.00.0.0	Commercial/Institutional	4,500
3.1.00.0.0	External Combustion	4,450
3.1.10.0.0	Coal	156
3.1.11.0.0	Bituminous[b]	100
3.1.11.1.0	Pulverized Dry	20
3.1.11.2.0	Pulverized Wet	1
3.1.11.4.0	All Stokers	79
3.1.12.0.0	Anthracite[c]	55
3.1.12.4.0	All Stokers	55
3.1.12.6.0	Spreader Stokers	0
3.1.13.0.0	Lignite[d]	1
3.1.13.4.0	All Stokers	1
3.1.13.6.0	Spreader Stokers	0
3.1.20.0.0	Petroleum	2,379
3.1.21.0.0	Residual Oil[e]	1,269
3.1.21.0.1	Tangential Firing	10
3.1.21.0.2	All Other	1,259
3.1.22.0.0	Distillate Oil[f]	1,110
3.1.22.0.1	Tangential Firing	11
3.1.22.0.2	All Other	1,099
3.1.30.0.0	Gas[g]	1,914
3.1.30.0.1	Tangential Firing	82
3.1.30.0.2	All Other	1,832
3.1.40.0.0	Refuse	1
3.1.42.0.0	Wood/Bark[h]	1
3.2.00.0.0	Internal Combustion	50
3.2.20.0.0	Petroleum	25
3.2.30.0.0	Gas	25

[a] Primarily space heating, except internal combustion which is primarily water pumping by municipalities and possibly a small amount of electric generation.

[b] 22.4 x 10^6 Btu/ton.

[c] 26.0 x 10^6 Btu/ton.

[d] 16.0 x 10^6 Btu/ton.

[e] 146,000 Btu/gal.

[f] 140,000 Btu/gal.

[g] 1,022 Btu/ft^3.

[h] 10.0 x 10^6 Btu/ton.

inconsequential and in most cases nonexistent; e.g., cooling water discharge, water treatment wastes, blowdown, etc. Solid waste emissions resulting from ash handling and coal storage operations are also minor, due to the small amount of coal used by the commercial/institutional sector. The principal sources of emissions are from the combustion stack. However, even though these emissions are uncontrolled, they are relatively minor in comparison with the electric utility and industrial combustion areas.

EXTERNAL COMBUSTION SYSTEM EMISSIONS

Total nationwide emission estimates of particulates (including <3 micron diameter particulates), sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, polycyclic organic matter, and trace elements are presented in Table 116 for commercial/institutional stationary external combustion sources. Commercial/institutional external combustion sources account for 1.0 percent of total particulates, 4.8 percent of sulfur oxides, 3.2 percent of nitrogen oxides, 0.1 percent of hydrocarbons, and 0.06 percent of carbon monoxide emissions from all man-made sources. They account for 4.8 percent of total particulates, 6.8 percent of sulfur oxides, 7.0 percent of nitrogen oxides, 12 percent of hydrocarbons, and 7.3 percent of carbon monoxide emissions from stationary combustion sources as determined by this study. The estimates are based on the EPA-NEDS emission factors listed in Table 117, and on the methods described in the notes following Table 116. To obtain state emission estimates for purposes of assigning priorities to the various combustion systems, it will be necessary to prorate the nationwide values by multiplying by the ratio of the fuel consumption in a state (ton/year) to the fuel consumption nationwide (ton/year). Fuel consumption estimates by state are provided in Appendix B. Additional data on trace element content are provided in Appendix C.

Table 116. FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[h] tons/yr		
		Total	< 3μ[p]	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
3.0.00.0.0	Commercial/Inst.	350	150	1,500	800	43	83	20,000	6.8	1.7
3.1.00.0.0	External Combustion	340	150	1,500	770	41	78	20,000	6.8	1.7
3.1.10.0.0	Coal	0.70	4.4	230	30	7.0	25	590	3.5	0.86
3.1.11.0.0	Bituminous[b]	0.50	3.0	210	14	6.8	23	380	2.3	0.56
3.1.11.1.0	Pulverized Dry	0.60	2.0	42	2.8	1.3	4.6	76	0.44	0.11
3.1.11.2.0	Pulverized Wet	4.8	0.08	2.1	0.14	0.067	0.023	3.8	0.022	0.0055
3.1.11.4.0	All Stokers	50	0.97	170	11	5.4	18	300	1.8	0.44
3.1.12.0.0	Anthracite[c]	21	0.41	20	16	0.21	2.1	210	1.2	0.30
3.1.12.4.0	All Stokers	21	0.41	20	16	0.21	2.1	210	1.2	0.30
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum	150	140	1,300	630	24	32	15,000	2.0	0.51
3.1.21.0.0	Residual Oil[d]	92	83	1,200	320	12	16	7,500	1.0	0.26
3.1.21.0.1	Tangential Firing	0.73	0.66	9.5	1.3	0.095	0.13	70	0.008	0.0021
3.1.21.0.2	All Other	91	82	1,200	320	12	16	7,400	1.0	0.26
3.1.22.0.0	Distillate Oil[e]	59	53	130	310	12	16	7,500	1.0	0.25
3.1.22.0.1	Tangential Firing	0.59	0.53	1.3	1.6	0.12	0.16	80	0.01	0.0025
3.1.22.0.2	All Other	58	52	130	310	12	16	7,400	1.0	0.25
3.1.30.0.0	Gas[f]	9.1	8.2	0.56	110	7.2	19	4,000	1.3	0.32
3.1.30.0.1	Tangential Firing	0.39	0.35	0.024	4.7	0.31	0.81	180	0.056	0.014
3.1.30.0.2	All Other	8.7	7.9	0.54	105	6.9	18	3,800	1.2	0.31
3.1.42.0.0	Wood/Bark[g]	1.4		0.10	0.69	2.5	2.1			

Table 116 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[i] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
3.0.00.0.0	Commercial/Inst.	1.8	39	60	54	0.96	54	160	59	10,000	79
3.1.00.0.0	External Combustion	1.8	39	60	54	0.96	54	160	59	10,000	79
3.1.10.0.0	Coal[j]	0.55	28	40	2.6	0.95	50	70	0.41	9,900	26
3.1.11.0.0	Bituminous[k]	0.48	27	34	2.3	0.95	50	68	0.40	6,700	13
3.1.11.1.0	Pulverized Dry	0.37	21	26	1.8	0.73	39	13	0.31	1,300	10
3.1.11.2.0	Pulverized Wet	0.015	0.85	1.0	0.072	0.029	1.6	0.68	0.012	68	0.42
3.1.11.4.0	All Stokers	0.09	5.0	6.6	0.43	0.19	9.6	54	0.016	5,400	2.6
3.1.12.0.0	Anthracite[l]	0.011	1.1	6.1	0.31	0.011	0.11	2.2	0.011	3,200	13
3.1.12.4.0	All Stokers	0.011	1.1	6.1	0.31	0.011	0.11	2.2	0.011	3,200	13
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum	1.2	11	20	2.8		3.3	89	59	500	53
3.1.21.0.0	Residual Oil[m]	1.2	9.4	20	2.8		3.3	5.3	59	500	53
3.1.21.0.1	Tangential Firing	0.0095	0.075	0.16	0.022		0.026	0.0053	0.47	5.0	0.43
3.1.21.0.2	All Other	1.2	9.3	20	2.8		3.3	5.3	58	500	53
3.1.22.0.0	Distillate Oil[n]	ND	1.3	ND				84	ND		ND
3.1.22.0.1	Tangential Firing	ND	0.013	ND				0.83	ND		ND
3.1.22.0.2	All Other	ND	1.3	ND				83	ND		ND
3.1.30.0.0	Gas[f]										
3.1.30.0.1	Tangential Firing										
3.1.30.0.2	All Other										
3.1.42.0.0	Wood/Bark[g]										

Table 116 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[i] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
3.0.00.0.0	Commercial/Inst.	79	330	700	4,100	19	5.0	1.7	72	1,500	13.4
3.1.00.0.0	External Combustion	79	330	700	4,100	19	5.0	1.7	72	1,500	13.4
3.1.10.0.0	Coal[j]	13	20	700	4,100	9.5	45	1.1	4.5	18	9.1
3.1.11.0.0	Bituminous[k]	3.5	12	360	3,400	8.6	44	0.57	3.4	13	8.8
3.1.11.1.0	Pulverized Dry	2.7	9.4	59	2,600	6.6	34	0.11	2.6	10	1.7
3.1.11.2.0	Pulverized Wet	0.11	0.36	2.3	100	0.26	1.3	0.0057	0.10	0.42	0.092
3.1.11.4.0	All Stokers	0.66	2.3	100	660	1.7	8.6	0.46	0.66	2.6	7.0
3.1.12.0.0	Anthracite[l]	9.6	7.9	340	710	0.94	1.4	0.52	1.1	5.3	0.29
3.1.12.4.0	All Stokers	9.6	7.9	340	710	0.94	1.4	0.52	1.1	5.3	0.29
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum	66	310	0.12	220	1.2	4.7	0.61	67	1,500	4.3
3.1.21.0.0	Residual Oil[m]	66	310	0.12	220	1.2	4.7	0.61	67	1,500	4.3
3.1.21.0.1	Tangential Firing	0.52	2.5	0.0012	1.7	0.0095	0.037	0.0061	0.52	12	0.043
3.1.21.0.2	All Other	65	310	0.12	220	1.2	4.7	0.61	66	1,500	4.3
3.1.22.0.0	Distillate Oil[n]		0.66				0.17	ND		ND	ND
3.1.22.0.1	Tangential Firing		0.0065				0.0017	ND		ND	ND
3.1.22.0.2	All Other		0.65				0.17	ND		ND	ND
3.1.30.0.0	Gas[o]										
3.1.30.0.1	Tangential Firing										
3.1.30.0.2	All Other										
3.1.42.0.0	Wood/Bark[g]										

Table 116 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

		Trace elements,[i] ton/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
3.0.00.0.0	Commercial/Inst.	0.31	0.12	16	880	55	1,700	30	49
3.1.00.0.0	External Combustion	0.31	0.12	16	880	55	1,700	30	49
3.1.10.0.0	Coal[j]	0.31	0.12	1.0	620	14	26	24	49
3.1.11.0.0	Bituminous[k]	0.30	0.095	0.90	560	14	26	21	44
3.1.11.1.0	Pulverized Dry	0.23	0.073	0.70	430	11	20	16	34
3.1.11.2.0	Pulverized Wet	0.0091	0.0029	0.027	18	0.44	0.78	0.62	1.4
3.1.11.4.0	All Stokers	0.056	0.019	0.17	110	2.7	4.7	3.9	8.6
3.1.12.0.0	Anthracite[l]	0.011	0.011	0.11	63	0.29	1.4	3.1	5.0
3.1.12.4.0	All Stokers	0.011	0.011	0.11	63	0.29	1.4	3.1	5.0
3.1.12.6.0	Spreader Stokers	0	0	0	0	0	0	0	0
3.1.13.0.0	Lignite	0	0	0	0	0	0	0	0
3.1.13.4.0	All Stokers	0	0	0	0	0	0	0	0
3.1.13.6.0	Spreader Stokers	0	0	0	0	0	0	0	0
3.1.20.0.0	Petroleum			15	160	41	1,700	5.6	
3.1.21.0.0	Residual Oil[m]				160	41	1,700	5.6	
3.1.21.0.1	Tangential Firing				1.3	0.32	13	0.044	
3.1.21.0.2	All Other				160	41	1,700	5.6	
3.1.22.0.0	Distillate Oil[n]			15			ND	ND	
3.1.22.0.1	Tangential Firing			0.15			ND	ND	
3.1.22.0.2	All Other			15			ND	ND	
3.1.30.0.0	Gas[o]								
3.1.30.0.1	Tangential Firing								
3.1.30.0.2	All Other								
3.1.42.0.0	Wood/Bark[g]								

Table 116 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

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[a] Values in the table represent total estimated emissions to the atmosphere from conventional stationary combustion sources in the United States. An entry of "ND" signifies that a trace element has not been detected when measured, and an entry left blank signifies that no information is available. The emission factors used in this table are given in Table 117.

[b] The consumption of bituminous coal was determined by taking the data from Table II, page 39, of reference 4 under the column headed "Retail Dealers" and subtracting the calculated residential consumption. The difference was believed to be the consumption by commercial/institutional users. The ash content was taken to be 13.8 percent by weight from Table 1-A, page 1, of reference 13. The sulfur content was taken to be 2.4 percent from Table 1-A, page 1, of reference 13.

[c] The consumption of anthracite was determined by subtracting the residential consumption from the consumption data given in reference 6. The ash content was assumed to be 10 percent; the sulfur content 0.5 percent.

[d] The consumption of residual oil was taken from Tables 6 and 12 of reference 2. The sulfur content was taken from reference 14 for 1973 oils and averaged 1.87 percent by weight.

[e] The consumption of distillate oil was determined by subtracting the residential consumption from reference 2. The sulfur content was taken from reference 14 for 1973 oils and averaged 0.225 percent by weight.

[f] The consumption of gas by conventional stationary combustion systems was estimated to be 65 percent of the value, in reference 3, for commercial and other consumers in 1973.

[g] The consumption of wood was updated from the emissions in the 1972 NEDS report.

[h] The emissions of BaP and BSO from all fuels were calculated from emission factors in reference 15. The emissions of particulate polycyclic organic matter (PPOM) from coal were based on a summation of emission factors for PYRENE, BENZO(a)PYRENE, BENZO(e)PYRENE, PERYLENE, BENZO(ghi)PERYLENE, ANTHANTHRENE, CORONENE, ANTHRACENE, PHENANTHRENE, AND FLUORANTHENE. PPOM emissions from oil and gas were calculated by assuming the same ratio to BaP as in the case of coal. Emission factors were specific to intermediate size combustion equipment. No data were found on emissions of polyhalogenated biphenyls from commercial/institutional systems.

Table 116 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

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[i] The amount of each trace element, i, emitted to the atmosphere was calculated as follows:

(1) The amount of i in the fuel, A_i, was

$$A_i = C_i \times F_i$$

where C_i = concentration of i in the fuel, ppm

F_i = yearly consumption of fuel, tons/year.

If A_i was calculated on a regional basis, results were summed to the national level.

(2) The amount emitted to the atmosphere, E_i, was

$$E_i = A_i \times f_i$$

where f_i = estimated fraction of i emitted to the atmosphere.

For the coal-fired pulverized dry bottom units $f_i = 0.85$, for pulverized wet bottom units $f_i = 0.65$, and for stokers $f_i = 0.05$. Exceptions are Br, Cl, and F for which $f_i = 1.0$, Hg for which $f_i = 0.90$, and Se for which $f_i = 0.70$. For oil $f_i = 1.0$.

[j] Data for coal were available for each of the coal-producing regions defined by the U.S. Geological Survey. Sources of trace element concentration data were publications by Magee,[16] Zubovic,[17] Kessler,[18] Ruch,[19] and von Lehmden.[20,21]

[k] For each coal-producing region, concentrations of As, Ba, Be, B, Cr, Co, Cu, F, Pb, Mn, Hg, Mo, Ni, Sn, U, V, and Zn in bituminous coal were calculated using reference 16 as a primary source and reference 17 as a supplementary source. For Cl, Br, and Ti, data from Illinois in reference 19 were used as typical of all coal-producing regions. For Sb, Bi, Cd, Fe, Te, Tl, and Zr, concentrations were calculated by using reference 18. For Se, the single concentration cited by reference 21 was used.

Table 116 (continued). FLUE GAS EMISSIONS FROM COMMERCIAL/INSTITUTIONAL EXTERNAL COMBUSTION, 1973[a]

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[l] For anthracite coal, typical trace element concentrations were taken from reference 18.

[m] For residual oil, trace element concentration data were available for As, Sb, Ba, Br, Cr, Mn, Ni, V, and Zn from reference 22. For the trace elements Be, B, Cd, Co, F, Fe, Pb, Hg, Mo, Se, Sn, Ti, and U, reference 21 was used as the primary source and references 20, 23, 24, and 25 as supplementary sources.

[n] For distillate oil, reference 22 reported concentrations for As, Br, Cu, Mn, and Sn and reported that Sb, Ba, Cd, Cr, Hg, Ni, Se, V, and Zn were not detectable.

[o] Hydrocarbon gases were assumed to be free of trace elements.

[p] For coal, emissions of < 3 micron particles were estimated as 2 percent of the total uncontrolled particulate emissions. For oil and gas, emissions of < 3 micron particles were estimated to be 90 percent of the particulate emissions.

Table 117. EMISSION FACTORS FOR TABLE 116

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
3.0.00.0.0	Commercial/Institutional	NA	NA	NA	NA	NA
3.1.00.0.0	External Combustion	NA	NA	NA	NA	NA
3.1.10.0.0	Coal[b]	NA	NA	NA	NA	NA
3.1.11.0.0	Bituminous	17A	38S	18	0.3	1
3.1.11.1.0	Pulverized Dry	13A	38S	30	0.3	1
3.1.11.2.0	Pulverized Wet	2A	38S	10	3	6
3.1.11.4.0	All Stokers	2A	38S	10	3	6
3.1.12.0.0	Anthracite	2A	38S	6	0.2	2
3.1.12.4.0	All Stokers	2A	38S	6	0.2	2
3.1.12.6.0	Spreader Stokers	X	X	X	X	X
3.1.13.0.0	Lignite	X	X	X	X	X
3.1.13.4.0	All Stokers	X	X	X	X	X
3.1.13.6.0	Spreader Stokers	X	X	X	X	X
3.1.20.0.0	Petroleum[c]	NA	NA	NA	NA	NA
3.1.21.0.0	Residual Oil	NA	NA	NA	NA	NA
3.1.21.0.1	Tangential Firing	23	159S	40	3	4
3.1.21.0.2	All Other	23	159S	80	3	4
3.1.22.0.0	Distillate Oil	NA	NA	NA	NA	NA
3.1.22.0.1	Tangential Firing	15	144S	40	3	4
3.1.22.0.2	All Other	15	144S	80	3	4
3.1.30.0.0	Gas[d]	10	0.6	120	8	20
3.1.30.0.1	Tangential Firing	10	0.6	120	8	20
3.1.30.0.2	All Other	10	0.6	120	8	20
3.1.42.0.0	Wood/Bark[b]	15	1.5	10	36	31

[a] Abbreviations used in the table have the following meanings:

A = Multiply by weight percent ash

S = Multiply by weight percent sulfur

X = Fuel consumed in this combustion system is small; emission is assumed to be negligible

NA = Not applicable.

[b] The emission factors for coal and wood/bark give values in terms of pounds of pollutant per ton burned.

[c] The emission factors for oil give values in terms of pounds of pollutant per 1000 gallons of oil burned.

[d] The emission factors for gas give values in terms of pounds of pollutant per 10^6 cubic feet of gas burned.

Barrett et al.[8] have conducted an EPA-sponsored field test program to measure criteria pollutant emissions from commercial oil-fired boilers. A summary of their test data, and a comparison with NEDS emission factors, is shown in Table 118. The test values were determined in a field study of eight distillate oil-fired, five residual oil-fired, and seven gas-fired units.

Table 118. EMISSION FACTORS: OIL-FIRED AND GAS-FIRED COMMERCIAL/INSTITUTIONAL BOILERS ($lb/10^6$ Btu)

Fuel	Data source	Particulate	SO_2	NO_x	HC	CO
Distillate oil	Battelle[8]	0.01	0.28	0.11	0.001	0.0035
	EPA[10]	0.1	0.3[a]	0.42	0.02	0.03
Residual oil	Battelle[8]	0.26	2.5	0.55	0.002	0.01
	EPA[10]	0.16	1.9[b]	0.42	0.02	0.03
Natural Gas	Battelle[8]	0.006	0.0006	0.1	0.004	0.02
	EPA[10]	0.02	0.0006	0.1	0.008	0.02

[a] 0.3 percent sulfur.

[b] 2.0 percent sulfur.

INTERNAL COMBUSTION SYSTEM EMISSIONS

The greatest commercial/institutional application of internal combustion engines is for the pumping of municipal water and sewage. Internal combustion engines are also used commercially to power pumps, compressors, and emergency power generators. In 1971, 167 million gallons of distillate oil and 22.5 billion cubic feet of natural gas were used by the commercial/institutional internal combustion sector.[11]

Total nationwide emission estimates are presented in Table 119. The estimates are based on the EPA-NEDS emission factors listed in Table 120, and on the methods described in the notes following Table 119. Commercial/institutional internal combustion sources account for 0.006 percent

Table 119. AIR EMISSIONS FROM COMMERCIAL/INSTITUTIONAL INTERNAL COMBUSTION, 1973[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[d] tons/yr		
		Total	<3μ[c]	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
3.0.00.0.0	Commercial/Institutional	350	150	1,500	800	43	83	20,000	6.8	1.7
3.2.00.0.0	Internal Combustion[b]	2.1		2.7	33	1.7	4.5			
3.2.20.0.0	Petroleum	2.1		2.7	25	1.7	4.5			
3.2.30.0.0	Gas	0		0.00068	7.5	0	0			

Table 119 (continued). AIR EMISSIONS FROM COMMERCIAL/INSTITUTIONAL INTERNAL COMBUSTION, 1973[a]

		Trace elements,[e] tons/yr								
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl
3.0.00.0.0	Commercial/Institutional	1.8	39	60	54	0.90	54	160	59	10,000
3.2.00.0.0	Internal Combustion		0.027					1.7		
3.2.20.0.0	Petroleum	ND	0.027	ND				1.7	ND	ND
3.2.30.0.0	Gas									

Table 119 (continued). AIR EMISSIONS FROM COMMERCIAL/INSTITUTIONAL INTERNAL COMBUSTION, 1973[a]

		Trace elements,[e] tons/yr								
		Cr	Co	Cu	F	Fe	Pb	Mn	Hg	Mo
3.0.00.0.0	Commercial/Institutional	170	79	330	700	4,100	19	50	1.7	72
3.2.00.0.0	Internal Combustion			0.014				0.0039	ND	
3.2.20.0.0	Petroleum	ND		0.014				0.0039	ND	
3.2.30.0.0	Gas									

Table 119 (continued). AIR EMISSIONS FROM COMMERCIAL/INSTITUTIONAL INTERNAL COMBUSTION, 1973[a]

		Trace elements,[e] tons/yr									
		Ni	Se	Te	Tl	Sn	Ti	U	V	Zn	Zr
3.0.00.0.0	Commercial/Institutional	1,500	13	0.31	0.12	16	880	55	1,700	30	49
3.2.00.0.0	Internal Combustion	ND	ND			0.24					
3.2.20.0.0	Petroleum	ND	ND			0.24					
3.2.30.0.0	Gas										

Table 119 (continued). AIR EMISSIONS FROM COMMERCIAL/INSTITUTIONAL INTERNAL COMBUSTION, 1973[a] of total particulates, 0.009 percent of sulfur oxides, 0.14 percent of nitrogen oxides, 0.005 percent of hydrocarbons, and 0.003 percent of carbon monoxide emissions from all man-made sources. They account for 0.03 percent of total particulates, 0.01 percent of sulfur oxides, 0.3 percent of nitrogen oxides, 0.5 percent of hydrocarbons, and 0.4 percent of carbon monoxide emissions from stationary combustion sources. To obtain state emission estimates for purposes of assigning priorities to the various combustion systems, it will be necessary to prorate the nationwide values by multiplying by the ratio of the fuel consumption in a state to the fuel consumption nationwide. Fuel consumption estimates by state are provided in Appendix B. Additional data on trace element content are provided in Appendix C.

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[a] Values in the table represent total estimated emissions to the atmosphere from conventional stationary combustion sources in the United States. An entry of "ND" signifies that a trace element has not been detected when measured; and an entry left blank signifies that no information is available. All emission factors used in this table are given in Table 120.

[b] Data on fuel consumption and capacities are from reference 11 and are based on 1971 values.

[c] No data were available on emissions of < 3 micron particles.

[d] No data were available for emissions of organics.

[e] Trace element emissions were based on consumption data and calculated trace element contents of the fuel as listed in Appendix C. These concentrations were multiplied by the fuel consumption to determine the total emissions of trace elements. For distillate oil, reference 22 reported concentrations for As, Br, Cu, Mn, and Sn, and reported that Sb, Ba, Cd, Cr, Hg, Ni, Se, V, and Zn were not detectable. Hydrocarbon gases were assumed to be free of trace elements.

Table 120. EMISSION FACTORS FOR TABLE 119

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
3.0.00.0.0	Commercial/Institutional	NA	NA	NA	NA	NA
3.2.00.0.0	Internal Combustion	NA	NA	NA	NA	NA
3.2.20.0.0	Petroleum[b]	5	144S	68	5.6	15.4
3.2.30.0.0	Gas[c]	14	0.6	413	42	115

[a] Abbreviations used in the table have the following meanings:

S = Multiply by weight percent sulfur

NA = Not applicable; emissions for this combustion system were calculated as the total of emissions from the appropriate subsystems.

[b] The emission factors for oil give values in terms of pounds of pollutant per 1000 gallons of oil burned.

[c] The emission factors for gas give values in terms of pounds of pollutant per 10^6 cubic feet of gas burned.

ASH HANDLING

It has been assumed that, because of the small size of commercial/institutional boilers, dry collection and landfill disposal will be the only method of bottom ash handling. Fly ash is not a factor since the application of control equipment is negligible in the commercial area except for some of the larger institutional boilers. Ash generation and air emission estimates from landfill are given in Table 121. The ash generation values given in the table are based on the difference between the ash content of the coal and the ash released to the atmosphere through the stack. The air emission values are based on the application of an emission factor of 1 lb/ton of ash collected. Solid waste pollutants resulting from leachates from landfill operations can be estimated from the bottom ash composition data presented in Section II and Appendix C for the coal fuels of importance. Ash from oil, gas, and other fuels will be negligible.

Table 121. ESTIMATED EMISSIONS FROM COMMERCIAL/INSTITUTIONAL ASH HANDLING, 1973[a]

		Ash generated, tons/year	Storage requirements, acre feet/year	Air emissions from landfill,[b] tons/year
3.0.00.0.0	Commercial/Institutional	700,000	319	350
3.1.00.0.0	External Combustion	700,000	319	350
3.1.10.0.0	Coal	700,000	319	350
3.1.11.0.0	Bituminous	460,000	209	230
3.1.11.1.0	Pulverized Dry	18,000	8	9
3.1.11.2.0	Pulverized Wet	2,000	1	1
3.1.11.4.0	All Stokers	440,000	200	220
3.1.12.0.0	Anthracite	235,000	105	110
3.1.12.4.0	All Stokers	235,000	105	110
3.1.13.0.0	Lignite	5,000	5	5
3.1.13.4.0	All Stokers	5,000	5	5
3.1.21.4.0	Residual Oil	Nil	Nil	Nil

[a] See Appendix C for fuel composition of bottom ash.

[b] Based on a landfill depth of 10 feet.

COOLING SYSTEMS

Cooling water requirements are not applicable to the commercial/institutional sector. The majority of commercial/institutional boilers are used for space heating and do not require the use of cooling water. The cooling water required for the few larger institutional boilers will be negligible.

OTHER WASTEWATER SOURCES

These emission streams are of minor consequence in this combustion area where small, low pressure boilers predominate. Estimates of waste volumes are less than 10^6 gallons per year.

COAL STORAGE

The coal storage requirements of commercial/institutional combustion sources are provided in Table 122. These values are based on an average storage requirement of 10 days. Storage pile height has been assumed to be 10 feet. Air emissions from coal pile storage will be negligible — less than 1 ton per year. Coal pile drainage volumes have been estimated assuming 50 percent open storage. Coal pile drainage composition can be obtained from data presented in Section II.

Table 122. COMMERCIAL/INSTITUTIONAL EMISSIONS FROM COAL STORAGE, 1973

		Tons stored	Storage requirements		Coal pile drainage,[a] 10^3 gal/year
			Area, acres/year	Volume, acre feet/year	
3.0.00.0.0	Commercial/Institutional				
3.1.00.0.0	External Combustion				
3.1.10.0.0	Coal	190,000	12	120	6,500
3.1.11.0.0	Bituminous	140,000	9	90	4,800
3.1.11.1.0	Pulverized Dry	29,000	2	20	950
3.1.11.2.0	Pulverized Wet	1,000	-	-	50
3.1.11.4.0	All Stokers	110,000	7	70	3,800
3.1.12.0.0	Anthracite	49,000	3	30	1,660
3.1.12.4.0	All Stokers	49,000	3	30	1,660
3.1.13.0.0	Lignite	1,000	-	-	40
3.1.13.4.0	All Stokers	1,000	-	-	40

[a] Assumed 50 percent open storage.

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SECTION V

RESIDENTIAL COMBUSTION SOURCES

Total fuel comsumption by the residential sector is estimated to be 10,350 x 10^{12} Btu/year, with 78 percent of this total utilized for space heating.[1] The remainder is used for various purposes such as cooking, water heating, air conditioning, etc. Fuel consumption estimates for the major fuel classifications are given in Table 123. The percentage of each fuel used for space heating is also provided in the table. The estimate of residential fuel usage is based on procedures described in reference 2, using information from references 3 to 12. The procedures involve the apportionment of fuel usage data for the combined commercial/residential sectors to the residential sector by considering the number of dwelling units in a state using each fuel, the degree days within each state, and the fuel requirements per degree day per dwelling unit.

Table 123. RESIDENTIAL FUEL USE, 1973

		Space heating, 10^{12} Btu/yr	Percent of fuel used for space heating
4.0.00.0.0	Residential	8,057	
4.1.00.0.0	External Combustion	8,057	78
4.1.10.0.0	Coal	192	100
4.1.11.0.0	Bituminous	115	100
4.1.12.0.0	Anthracite	75	100
4.1.13.0.0	Lignite	2	100
4.1.20.0.0	Petroleum[a]	2,280	94
4.1.22.0.0	Distillate Oil	2,280	94
4.1.30.0.0	Gas	5,450	70
4.1.42.0.0	Wood	135	100

[a] Over 95 percent No. 1 or No. 2 distillate oil.

NUMBER AND CHARACTERISTICS OF BOILERS

The literature contains few references to the number and characteristics of residential combustion sources other than those provided by the Bureau of Census.[3] The number of individual sources tabulated below has been estimated from oil-fired equipment data:[13]

Oil-fired units	11×10^6
Gas-fired units	27×10^6
Coal-fired units	1×10^6
Total	39×10^6.

The population of coal- and gas-fired units was estimated by assuming that the fuel unit population was a direct function of fuel consumption used for space heating. Sales data by type and size of oil-fired equipment are also provided in reference 13 and are summarized in Tables 124 and 125. Although a general survey of existing burner population by detailed burner and system type is not available, data presented in these tables provide guidelines for estimating population and selecting representative equipment mix. The size distribution provided in Table 125 can be assumed to be representative of natural gas equipment also, although variations due to geographic and climatic differences are conceivable.

Table 124. SALES OF DOMESTIC OIL BURNERS BY TYPE[13]

Oil burner type	1969, percent	Pre-1941, percent
High-pressure gun burners	95.0	71.7
Low pressure burners	3.4	6.2
Vertical-rotary burners	0.4	11.0
Vaporizing burners	1.2	10.8
Miscellaneous types	-	0.3

Table 125. DISTRIBUTION OF SIZES OF DOMESTIC OIL-FIRED EQUIPMENT[13]

By firing rates, gph,[a] all 1970 installations		By boiler sizes, 10^3 Btu/hr		By furnace sizes, 10^3 Btu/hr	
Rate	Percent	Size	Percent	Size	Percent
< 1.0	32	< 75	3	< 50	2
1.0 - 1.35	37	76 - 100	26	50 - 75	11
1.35 - 1.65	12	101 - 125	45	76 - 100	42
1.66 - 2.0	7	126 - 150	16	101 - 125	32
2.01 - 3.0	7	> 150	10	> 125	13
> 3.0	5				

[a] Gallons per hour.

FLUE GAS EMISSIONS

Total nationwide emission estimates of particulates (including < 3 micron diameter particulates), sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, polycyclic organic matter, and trace elements are presented in Table 126 for residential space heating combustion sources. The estimates are based on the EPA-NEDS emission factors listed in Table 127, and on the methods described in the notes following Table 126.

Residential combustion sources account for 0.7 percent of total particulates, 4.2 percent of sulfur oxides, 1.5 percent of nitrogen oxides, 0.3 percent of hydrocarbons, and 0.3 percent of carbon monoxide emissions from all man-made sources. They account for 3.3 percent of total particulates, 6.3 percent of sulfur oxides, 3.2 percent of nitrogen oxides, 31 percent of hydrocarbons, and 44 percent of carbon monoxide emissions from the stationary combustion sources considered in this study.

Table 126. FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Particulates, 10^3 tons/yr		Gases, 10^3 tons/yr				Organics,[i] tons/yr		
		Total	$<3\mu^{q}$	SO_x	NO_x	HC	CO	BSO	PPOM	BaP
4.0.00.0.0	Residential	230	120	1,400	350	110	470	69,000	4,100	390
4.1.00.0.0	External Combustion	230	120	1,400	350	110	470	69,000	4,100	390
4.1.10.0.0	Coal	69	1.3	240	12	57	370	43,000	4,000	380
4.1.11.0.0	Bituminous[b,c]	53	1.0	210	7.9	53	240	26,000	2,400	230
4.1.12.0.0	Anthracite[b,d]	15	0.29	27	4.3	3.6	130	17,000	1,600	150
4.1.13.0.0	Lignite[e]	1.4	0.027	1.0	0.3	0.05	0.1	450	42	3.6
4.1.20.0.0	Petroleum	82	74	1,200	98	25	41	14,000	11	1.1
4.1.22.0.0	Distillate Oil[f]	82	74	1,200	98	25	41	14,000	5.2	0.50
4.1.30.0.0	Gas[g]	52	47	1.5	210	21	54	12,000	6.3	0.60
4.1.42.0.0	Wood/Bark[h]	25	0.49	3.7	25	5.0	5.0	840	77	7.4

Table 126 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr									
		Sb	As	Ba	Be	Bi	B	Br	Cd	Cl	Cr
4.0.00.0.0	Residential	0.031	1.9	3.2	0.16	0.053	2.7	83	0.021	12,000	2.4
4.1.00.0.0	External Combustion	0.031	1.9	3.2	0.16	0.053	2.7	83	0.021	12,000	2.4
4.1.10.0.0	Coal[k]	0.031	1.8	3.2	0.16	0.053	2.7	81	0.021	12,000	2.4
4.1.11.0.0	Bituminous[l]	0.03	1.6	1.9	0.12	0.05	2.6	78	0.020	7,800	0.7
4.1.12.0.0	Anthracite[m]	0.001	0.15	0.89	0.04	0.001	0.015	2.9	0.0010	4,400	1.7
4.1.13.0.0	Lignite[n]			0.42		0.002	0.057			16	0.006
4.1.20.0.0	Petroleum	ND	0.05	ND				2.0	ND		ND
4.1.22.0.0	Distillate Oil[o]	ND	0.05	ND				2.0	ND		ND
4.1.30.0.0	Gas[p]										
4.1.42.0.0	Wood/Bark										

Table 126 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr									
		Co	Cu	F	Fe	Pb	Mn	Hg	Mo	Ni	Se
4.0.00.0.0	Residential	1.5	1.9	740	280	0.64	26	1.4	0.35	1.5	10
4.1.00.0.0	External Combustion	1.5	1.9	740	280	0.64	26	1.4	0.35	1.5	10
4.1.10.0.0	Coal[k]	1.5	1.8	740	280	0.64	26	1.4	0.35	1.5	10
4.1.11.0.0	Bituminous[l]	0.20	0.7	420	180	0.5	23	0.65	0.2	0.8	10
4.1.12.0.0	Anthracite[m]	1.3	1.1	320	99	0.13	2.6	0.78	0.15	0.73	0.4
4.1.13.0.0	Lignite[n]	0.005	0.008			0.009	0.039	0.002	0.004		
4.1.20.0.0	Petroleum		0.05				0.006	ND		ND	ND
4.1.22.0.0	Distillate Oil[o]		0.05				0.006	ND		ND	ND
4.1.30.0.0	Gas[p]										
4.1.42.0.0	Wood/Bark										

Table 126 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

		Trace elements,[j] tons/yr							
		Te	Tl	Sn	Ti	U	V	Zn	Zr
4.0.00.0.0	**Residential**	0.021	0.006	0.18	40	0.8	1.6	3.1	3.8
4.1.00.0.0	**External Combustion**	0.021	0.006	0.18	40	0.8	1.6	3.1	3.8
4.1.10.0.0	Coal[k]	0.021	0.006	0.064	40	0.8	1.6	3.1	3.8
4.1.11.0.0	Bituminous[l]	0.020	0.005	0.05	31	0.8	1.4	1.1	2.4
4.1.12.0.0	Anthracite[m]	0.001	0.001	0.01	8.7	0.004	0.19	2.0	1.4
4.1.13.0.0	Lignite[n]			0.004			0.012	0.018	
4.1.20.0.0	Petroleum			0.12			ND	ND	
4.1.22.0.0	Distillate Oil[o]			0.12			ND	ND	
4.1.30.0.0	Gas[p]								
4.1.42.0.0	Wood/Bark								

Table 126 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

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[a] Values in the table represent total estimated emissions to the atmosphere from conventional stationary combustion sources in the United States. An entry of "ND" signifies that a trace element has not been detected when measured; and an entry left blank signifies that no information is available. All the emission factors used in this table are given in Table 127.

[b] The consumption data for anthracite and bituminous coal were calculated according to the formula described in reference 2. This formula considers the number of dwelling units in a state using coal as a heating fuel, the degree days, and the coal heating requirement factor of 0.0012 ton coal per degree day per dwelling unit. State total coal consumed = (Number of dwelling units x degree days x 0.0012) ton/year. The number of heating units was obtained from reference 3 and the degree days from reference 4. The total residential coal consumption was calculated for the year 1970, for each state and combined by the geographical regions listed in reference 5. The calculated coal consumption by households was ratioed to coal received by retail dealers in 1970 according to reference 6 to obtain the percentage of coal used by residential as opposed to commercial users. This percentage was applied to the 1973 data obtained from reference 7 to obtain a more recent estimate.

Anthracite consumption was obtained from reference 8. According to reference 2, in states where anthracite consumption exceeded the total quantity of coal used in residential heating, the total consumption was considered as anthracite. In states where anthracite deliveries were less than the consumption, the difference was assumed to be bituminous coal. In states where anthracite was not available, the total residential coal consumption was considered to be bituminous coal.

[c] The sulfur content was obtained from reference 5 for individual states.

[d] The sulfur content was assumed to be 0.5 percent.

[e] Lignite consumption was obtained from reference 12. Sulfur content was assumed to be 0.6 percent; ash content 9.6 percent.

[f] Distillate oil consumption as residential fuel was calculated according to reference 3, by multiplying the number of dwelling units burning oil in a state taken from reference 4 by the degree days and by the heating requirement factor of 0.18 gallon oil per degree day. State total consumed = (Number of dwelling units x degree day x 0.18) gal/year. Sulfur content was obtained from reference 9.

Table 126 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

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[g] Natural gas consumption was obtained from reference 10, page 8, under residential use. Combined residential and commercial LPG consumption data were obtained from reference 11, page 4. The fraction used in residential units as opposed to commercial units in each state was assumed to be the same as for natural gas. The emissions were combined for natural gas and LPG.

[h] Wood consumption as residential fuel was calculated according to reference 2, by multiplying the number of dwelling units burning wood taken from reference 3 with the degree days in a given state taken from reference 4 and the heating requirement factor of 0.0017 ton of wood per dwelling unit degree day. State total wood consumed = (Number of dwelling units x degree day x 0.0017) tons/year. The wood consumption was combined for regions and for the country. The value in the table includes also emissions from the ten million tons of wood burned in fireplaces annually in the United States, estimated in reference 15.

[i] The emissions of BaP and BSO from all fuels were calculated from emission factors in reference 16. The emissions from coal of particulate polycyclic organic matter (PPOM) were based on a summation of emission factors for PYRENE, BENZO(a)PYRENE, BENZO(e)PYRENE, PERYLENE, BENZO(ghi)PERYLENE, ANTHANTHRENE, CORONENE, ANTHRACENE, PHENANTHRENE, FLUORANTHENE. PPOM emissions from oil and gas were calculated by assuming the same ratio of BaP as in the case of coal. Emission factors were specific to residential size combustion equipment. No data were found on emissions of polyhalogenated biphenyls from residential combustion.

[j] The amount of each trace element, i, emitted to the atmosphere was calculated as follows:

(1) The amount of i in the fuel, A_i, was

$$A_i = C_i \times F_i$$

where C_i = concentration of i in the fuel, ppm

F_i = yearly consumption of fuel, tons/year.

If A_i was calculated on a regional basis, results were summed to the national level.

Table 126 (continued). FLUE GAS EMISSIONS FROM RESIDENTIAL COMBUSTION, 1973[a]

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(2) The amount emitted to the atmosphere, E_i, was

$$E_i = A_i \times f_i$$

where f_i = estimated fraction of i emitted to the atmosphere.

Values of f_i were small, as a large fraction of the emissions are soot. For bituminous coal $f_i = 0.01$, for anthracite $f_i = 0.005$, for lignite $f_i = 0.014$, for distillate oil $f_i = 0.005$. Exceptions are Br, Cl, and F for which $f_i = 1.0$, Hg for which $f_i = 0.90$ and Se for which $f_i = 0.70$.

[k] Data for coal were available for each of the coal-producing regions defined by the U.S. Geological Survey. Sources of trace element concentration data were publications by Magee,[17] Zubovic,[18] Ruch,[19] and von Lehmden.[20,21]

[l] For each coal-producing region, concentrations of As, Ba, Be, B, Cr, Co, Cu, F, Pb, Mn, Hg, Mo, Ni, Sn, U. V, and Zn in bituminous coal were calculated using reference 17 as a primary source and reference 18 as a supplementary source. For Cl, Br, and Ti, data from Illinois in reference 19 were used as typical of all coal-producing regions. For Sb, Bi, Cd, Fe, Te, Tl, and Zr, concentrations were calculated by using reference 22. For se, the single concentration cited by reference 21 was used.

[m] For anthracite coal, typical trace element concentrations were taken from reference 22.

[n] For lignite, reference 17 supplied the data for North Dakota lignite and reference 18 supplied the data for Texas lignite. Reference 17 contained data for the elements As, Ba, Be, Bi, B, Br, Co, Cu, Cr, Mn, Mo, Ni, Sn, V, Zn, and Zr. Reference 18 contained data for the elements Be, Br, Co, Cu, Mo, Ni, Sn, V, and Zr. A concentration of Cl in lignite was obtained from reference 23. Lignite consumption in 1974 consisted of 6.9×10^6 tons from North Dakota and 5.7×10^6 tons from Texas, according to reference 11.

[o] For distillate oil, reference 24 reported concentrations for As, Br, Cu, Mn, and Sn and reported that Sb, Ba, Cd, Cr, Hg, Ni, Se, V, and Zn were not detectable.

[p] Hydrocarbon gases were assumed to be free of trace elements.

[q] Emissions of < 3 microns particulates were assumed to be 2 percent of the total particulate emissions for coal. For oil and gas, 90 percent of the particulates were assumed to be < 3 microns.

Table 127. EMISSION FACTORS FOR TABLE 126

		Particulates[a]	Gases[a]			
		Total	SO_x	NO_x	HC	CO
4.0.00.0.0	Residential	NA	NA	NA	NA	NA
4.1.00.0.0	External Combustion	NA	NA	NA	NA	NA
4.1.10.0.0	Coal[b]	NA	NA	NA	NA	NA
4.1.11.0.0	Bituminous	20	38S	3	20	90
4.1.12.0.0	Anthracite	10	36.8S	3	2.5	90
4.1.13.0.0	Lignite	3A	30S	6	1	2
4.1.20.0.0	Petroleum[c]	10	144S	12	3	5
4.1.22.0.0	Distillate Oil	10	144S	12	3	5
4.1.30.0.0	Gas[d]	10	0.6	80	8	20
4.1.42.0.0	Wood/Bark[b]	10	1.5	10	36	31

[a] Abbreviations used in the table have the following meanings

A = Multiply by weight percent ash

S = Multiply by weight percent sulfur

NA = Not applicable.

[b] The emission factors for coal and wood/bark give values in terms of pounds of pollutant per ton burned.

[c] The emission factors for oil give values in terms of pounds of pollutant per 1000 gallons of oil burned.

[d] The emission factors for gas give values in terms of pounds of pollutant per 10^6 cubic feet of gas burned.

A comparison of recent field measurements (for 30 oil-fired units[14] and 2 gas-fired units[13]) with EPA emission factors[25] is presented in Table 128. Hydrocarbon emissions from oil-fired units appear to be lower than reported EPA emission factors. Recent studies[26-28] have provided more data on residential emissions, including the effects of excess air and burner modifications. The particle size distribution of emissions from oil-fired units has been measured.[29]

Table 128. COMPARISON OF EMISSION FACTORS FOR RESIDENTIAL COMBUSTION UNITS

Fuel	Emission factors, lb/10^6 Btu				
	Particulate	SO_2	NO_x	HC	CO
Oil-fired units					
Reference 14	0.06	0.3[b]	0.13	0.005	0.06
EPA[a]	0.07	0.3[b]	0.09	0.02	0.04
Gas-fired units					
Reference 13	0.005	0	0.08	0.004	0.02
EPA[a]	0.02	0.0006	0.08	0.008	0.02

[a] Reference 25.

[b] For 0.3 percent sulfur.

Most emissions from residential combustion sources constitute minor fractions of total combustion source emissions. A notable exception in the case of air emissions is the emission of polycyclic organic matter (POM). Although the data quality is not high, residential coal-fired furnaces, because of their low combustion efficiency, are the principal combustion source of POM.[16] Residential oil combustion is also suspected as a possible cause of high sulfate levels in eastern urban areas.[29]

To obtain state emission estimates for purposes of assigning priorities to the various combustion systems, it will be necessary to prorate the nationwide values by multiplying by the ratio of the fuel consumption in a state to the fuel consumption nationwide. Fuel consumption estimates by state are provided in Appendix B. Additional data on trace element content are provided in Appendix C.

OTHER EMISSIONS

The only other waste stream contributing to environmental pollution is that due to ash disposal. However, this is relatively minor since coal and other high ash fuels are not consumed to any extent for residential space heating. Total ash produced is about 800,000 tons/year. This ash will be disposed of as landfill, with the major portion handled by municipal disposal methods.

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SECTION VI

TRENDS IN FOSSIL FUEL CONSUMPTION

The prediction of fossil fuel consumption patterns over the next 10 years is dependent on political (local, state, national and international), economic, environmental and technological considerations. As an illustration of this complexity, the factors affecting fuel and electricity supply and demand over the past several years can be examined, since these factors continue to change and influence the fuel supply and consumption situation. One extremely important factor is the pricing policy of the Oil Producing and Exporting Countries (OPEC). During the 1-year period January 1973 to January 1974, OPEC increased the price of crude oil by a factor of 4,[1] and as a result the price of refined oil as purchased by U.S. steam electric plants subsequently tripled[2] (see Figure 30). The price of oil affected the price of other energy sources, causing coal and natural gas prices to rise sharply although not nearly as rapidly as oil prices. During the 1960's the price of imported oil remained relatively constant in the range of $1.50 to $1.75 per barrel,[1] and well below the most current price of $13.50 per barrel.[3] Clearly, any studies conducted during the 1960's to estimate fuel consumption patterns in the 1970's have been invalidated by the sudden changes in 1973.

Federal regulations and policies also strongly affect fuel-use patterns. In the past, environmental laws encouraged utilities to switch from coal to oil. At the present time, the Federal Energy Administration is involved in procedures to force many oil and/or gas burning utility boilers to switch back to coal and to force some new plants now being planned to burn coal.[4]

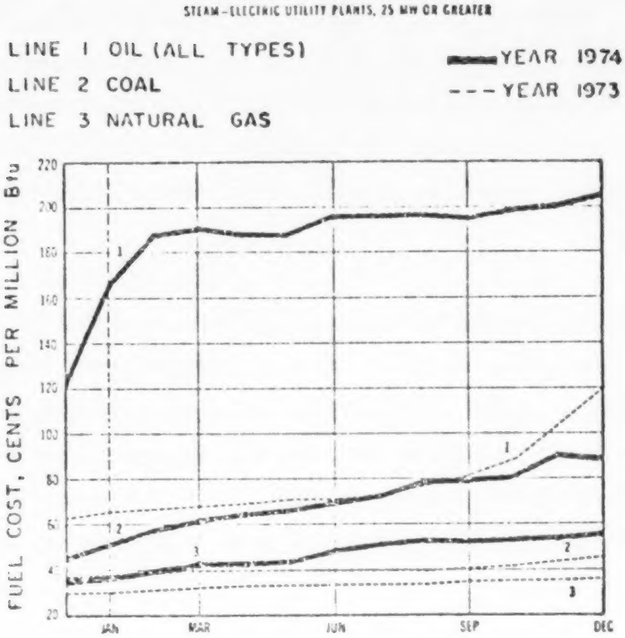


Figure 30. Monthly cost of fossil fuels delivered to U.S. steam-electric utility plants, 25 MW or greater

The Federal government is also involved in the pricing of fossil fuels, thus affecting energy-use patterns. In the spring of 1975 the U.S. Government imposed a $2.00 per barrel tariff on imported oil which raised the total price to $13.50 per barrel. At the same time domestic oil was controlled at a price of $5.25 per barrel. The courts have since declared the $2.00 per barrel tariff to be illegal.[5] In addition, the price of domestic oil is scheduled to be decontrolled on August 31, 1975. These variations in oil prices affect both the oil supply and demand.

Only a few of the many factors affecting fuel-use patterns were discussed in the above paragraphs. Federal regulations and environmental considerations strongly influence the development of western coal resources through strip mining. Development of mines, electric power plants and large equipment delivery are subject to very long lead times, in the range of 2 to 7 years. Manpower availability and training also affect the development of energy resources. Advanced energy technologies such as coal gasification or liquifaction, magnetohydrodynamics, solar energy and fusion power are not expected to produce significant amounts of energy by 1985, although unexpected technological breakthroughs may alter the situation.[6]

The majority of the trends discussed in this section are based on the Federal Energy Administration's Project Independence Report published in November 1974.[7] Many other energy related references[8-14] were consulted and used to supplement the Project Independence Report, but the Project Independence Report was judged to be the most recent and reliable analysis available. However, the Project Independence studies only considered three prices for imported oil, $4, $7, and $11 per barrel. The most current price for imported oil is $13.50 per barrel, including the tariff, and OPEC is considering a 30 to 40 percent increase for the fall of 1975.[15] Therefore, the shift toward coal may be stronger than predicted in the Project Independence Report.

Analysis of fuel use and trend data indicates that energy use will increase 29 percent from 1973 to 1985 in the conventional combustion systems considered in this study, as shown in Table 129. Coal use will increase 87 percent, oil use will decrease 2 percent and natural gas use will increase 13 percent. The large increase in coal consumption will be confined to the electric utility and industrial sectors while the increase in natural gas consumption will be confined to the commercial and residential sectors. These trends indicate a potential increase in those pollutants associated with coal, either as an air, water, or solid waste pollutant. The actual change in emissions to the air will depend on coal properties (i.e., ash, trace element, and sulfur content) and the application and effectiveness of particulate and sulfur oxide control equipment. Additional water and solid waste pollutants will be generated by the increased coal combustion and control equipment operation. The use

Table 129. FUEL CONSUMPTION TRENDS: STATIONARY COMBUSTION SOURCES[a]

	1973[b] fuel use, 10^{12} Btu	1985 fuel use, 10^{12} Btu	Percent change, 1973[b]-1985
Total	38,701[c,d,g]	49,843[e,f,g]	+29
Coal	10,220	19,095	+87
Oil	9,958	9,801	-2
Gas	18,523	20,947	+13
Electric Utilities	15,387	22,531[e]	+46
Coal	8,502	16,994	+100
Oil	3,351	3,016	-10
Gas	3,534	2,485	-30
Industrial	11,300[c]	12,934[f]	+14
Coal	1,370	1,945	+42
Oil	2,060	2,966	+44
Gas	7,600	7,600	+0
Commercial/Institutional	4,500[d]	4,941	+10
Coal	156	70	-55
Oil	2,404	2,019	-16
Gas	1,939	2,851	+47
Residential	8,057[g]	9,258[g]	+15
Coal	192	86	-55
Oil	2,143	1,800	-16
Gas	5,450	8,011	+47

[a] Electric generation process steam, space heating, and stationary engines.

[b] Utility data represents 1974.

[c] Includes 250 x 10^{12} Btu wood and 20 x 10^{12} Btu bagasse.

[d] Includes 1 x 10^{12} Btu wood.

[e] Includes 36 x 10^{12} Btu refuse.

[f] Includes 400 x 10^{12} Btu wood and 23 x 10^{12} Btu bagasse.

[g] Includes 135 x 10^{12} Btu wood.

of western coal (coal supply regions 16 to 23) will increase relative to eastern coal, possibly causing a decrease in the amount of SO_2 emitted per unit of fuel burned, as discussed in detail in the electric generation section.

ELECTRIC GENERATION

Fuel Use Trends

During the past 35 years the consumption of fossil fuels for the production of electricity has increased at about 7 percent per year with a doubling interval of about 10 years.[16,17] However, from 1973 to 1974 the consumption of fossil fuel by the electric utility industry declined 3.5 percent[18] due to the recession and the sharply increased energy costs. As shown in Table 129, the consumption of fossil fuel by the electric utility industry is expected to increase 46 percent from 1974 to 1985, a growth rate of only 3.5 percent per year compared to the past growth rate of 7 percent per year. Total electric energy production (including hydropower and nuclear) is expected to increase at a higher rate of 5.9 percent per year due to an expected fourteenfold increase in nuclear power.[10]

Coal consumption will increase sharply[6-10] while oil and gas consumption will decline.[1,7,9,10] A decline in natural gas consumption was not unexpected as it is due to limited domestic reserves and was predicted in 1972[8] before the sudden changes in energy prices. Estimates of the increase in coal consumption range from 50 to 100 percent.[6-10] Trends in oil consumption are very uncertain due to the highly volatile price situation and still developing government programs.

Our estimates of electric utility fuel consumption trends are presented in Table 130. Specifically, the use of bituminous coal and lignite will increase sharply while the use of anthracite will decline. Anthracite consumption by the electric utility industry has declined from 2,240,000 tons in 1964 to 1,460,000 tons in 1974. A study published in 1970 predicted that anthracite consumption by the electric utility industry would decline 6.5 percent per year to the year 2000.[11] A more recent study, based on an $11 per barrel crude oil price, predicted a decline in demand of about 4 percent per year from 1974 to 1985 or a total decline in anthracite consumption of 50 percent.[12] The installed capacity of lignite-fired electric generation boilers is expected to increase by a factor of about 10 from 1974 to 1985[9] and thus the amount of lignite burned should increase by a factor of 10. We used the Project Independence[7] coal estimate of an increase of 100 percent from 1974 to 1985, based on business as usual with an $11 per barrel world market oil price. The estimates of a 50-percent decline in anthracite, a tenfold increase in lignite, and a 100-percent increase in coal, indicate an 81-percent increase in bituminous coal consumption.

Table 130. SUMMARY OF ELECTRIC UTILITY FUEL CONSUMPTION TRENDS TO 1985

		1974 fuel use, 10^{12} Btu	1985 fuel use, 10^{12} Btu	Percent change, 1974-1985
1.0.00.0.0	Electric Generation	15,387	22,531	+46
1.1.00.0.0	External Combustion	14,798	20,932	+42
1.1.10.0.0	Coal	8,502	16,994	+100
1.1.11.0.0	Bituminous	8,264	14,975	+81
1.1.12.0.0	Anthracite	38	19	-50
1.1.13.0.0	Lignite	200	2,000	+1000
1.1.20.0.0	Petroleum	3,039	2,172	-29
1.1.21.0.0	Residual Oil	2,901	2,060	-29
1.1.22.0.0	Distillate Oil	138	99	-29
1.1.30.0.0	Gas	3,257	1,780	-55
1.1.40.0.0	Refuse	0.6	36	+6000
1.2.00.0.0	Internal Combustion	589	1,549	+262
1.3.00.0.0	Turbine	515	1,467	+285
1.3.20.0.0	Oil	286	815	+285
1.3.30.0.0	Gas	229	652	+285
1.4.00.0.0	Reciprocating	74	82	+10
1.4.20.0.0	Oil	26	29	+10
1.4.30.0.0	Gas	48	53	+10

Assuming business as usual and an $11 per barrel world market price for oil, oil use by the utility industry should be 3,000 x 10^{12} Btu in 1985 (down 10 percent from 1974) and gas use should be 2,500 x 10^{12} per year (down 30 percent).[7] Gas and oil will be burned in conventional steam-electric plants, combined cycle plants, simple turbines and reciprocating engines. Reciprocating engines consume a small fraction of utility fossil fuel (0.5 percent) and the growth has been very slow (50 percent increase in 25 years). In line with the 1973 to 1974 increase in capacity of 1 percent, GCA estimates that oil and gas use in reciprocating engines will increase by 10 percent from 1974 to 1985. There is a comparatively large uncertainty involved in estimating fuel use in turbine systems. The Project Independence Report estimated that combustion turbine capacity would increase by a factor of 5 from 1973 to 1985, based primarily on a very large increase in the use of combined cycle plants.[7] This type of plant was first commercially installed in 1971 and 1972, has a higher efficiency than simple turbines or steam-electric systems, and looked very promising for intermediate load operation. However, combined cycle plants use gaseous or premium liquid fuels (which are in short supply and are high priced) and have a capital cost 2.5 times greater than simple turbines.[13] During the past few years, new orders for combined cycle plants have been at a standstill and during 1974 orders for combustion turbines fell sharply.[13] We estimated that the gas turbine growth will be less than the Project Independence estimate of 500 percent and selected the growth rate of the past few years (10 percent per year or 280 percent to 1985). This estimate is based on a linear extrapolation of the growth rate experienced by gas turbines over the period 1968 to 1974 as illustrated in Figure 31. The fuel mix was assumed to be the same as the present mix. The remaining oil and gas use, as estimated in the Project Independence Report, was assigned to the external combustion category. Thus, oil burned in utility boilers should decline 29 percent by 1985 and gas burned should decline 55 percent. The ratio of residual oil to distillate oil used by external combustion systems in 1985 is assumed to be the same as 1974.

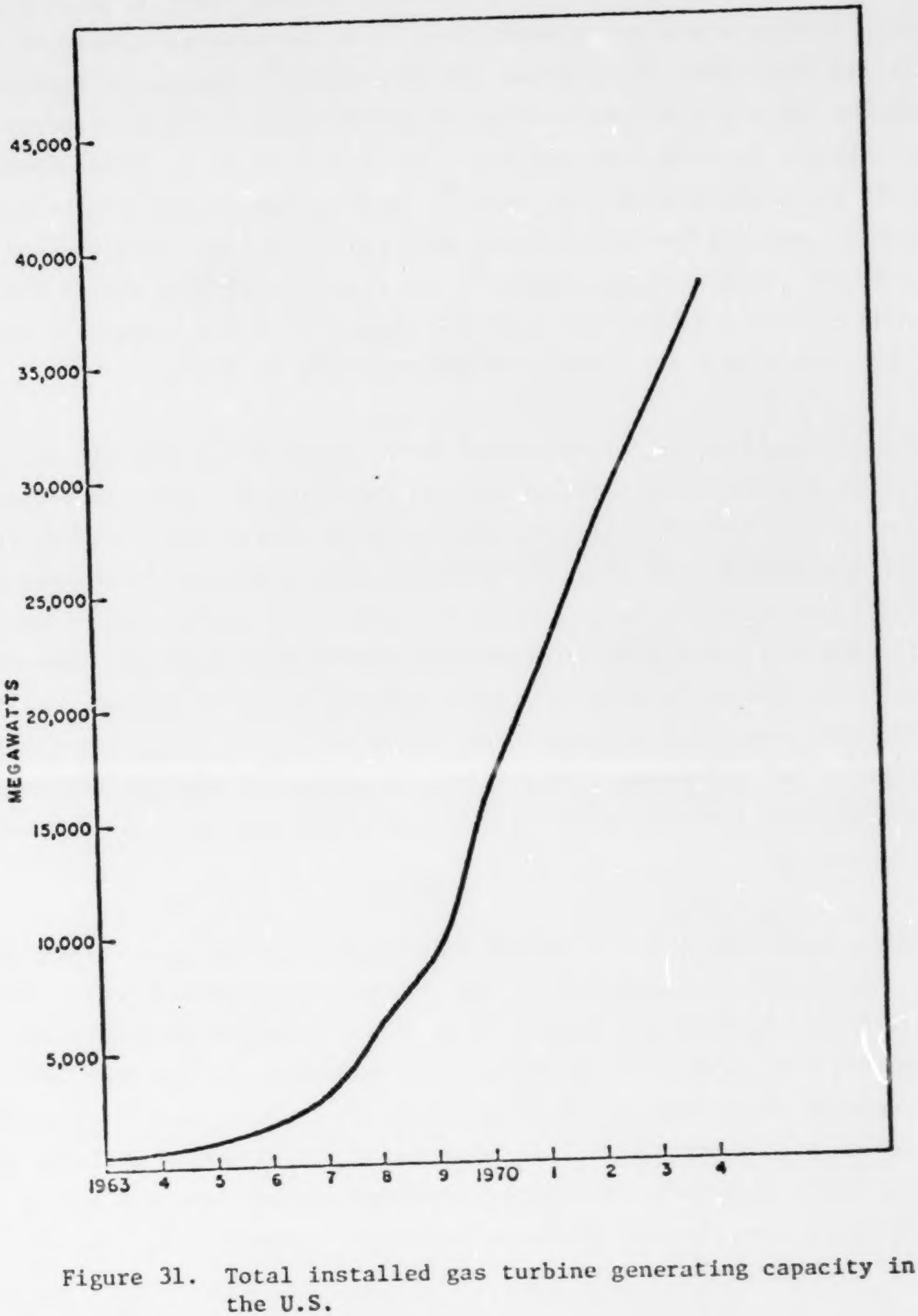
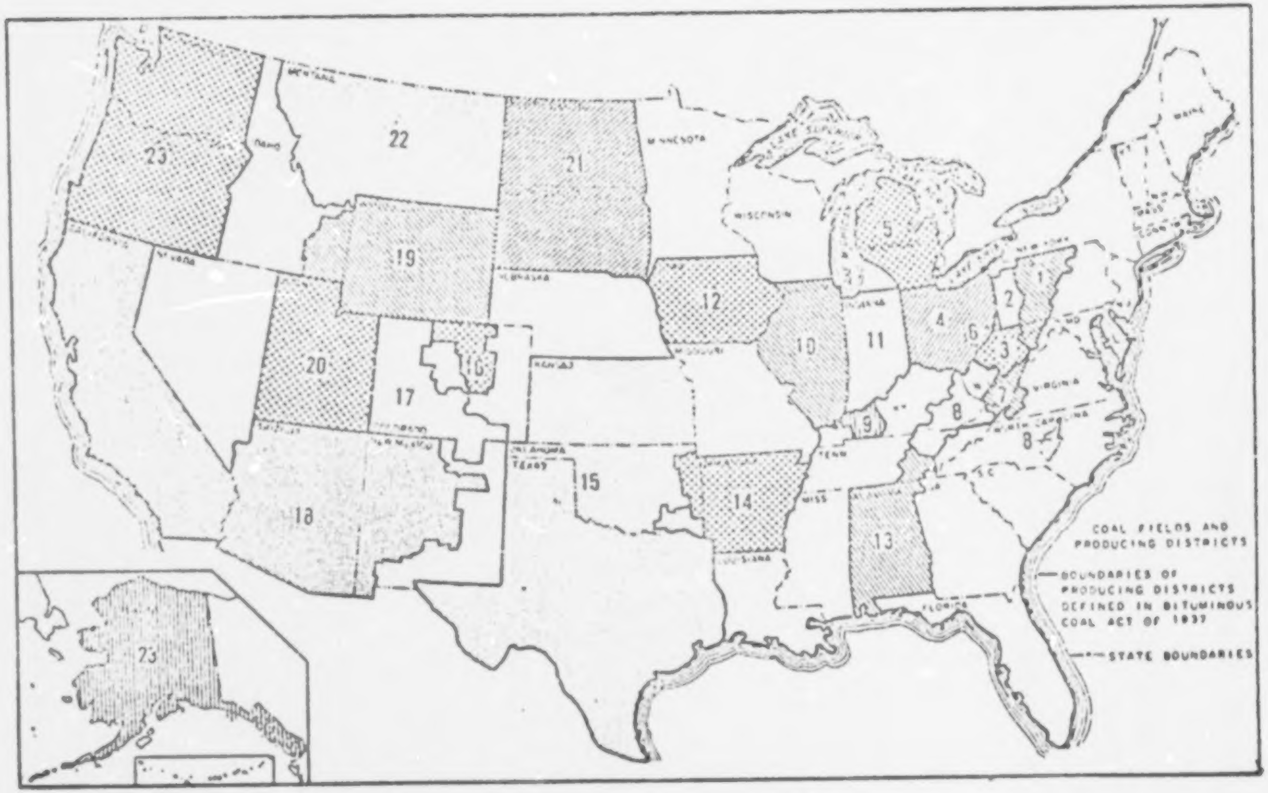


Figure 31. Total installed gas turbine generating capacity in the U.S.

The combustion of refuse by utilities to produce electricity is limited at this time, with only the Union Electric Meramac Plant in St. Louis County burning significant quantities.[19] At the present time Union Electric can burn about 300 tons per day of refuse.[20] Contracts, however, have been let for a $70 million project to expand Union Electric's refuse burning capacity to 8,000 tons per day — the total amount of refuse generated in the St. Louis metropolitan area.[21] Many cities are planning energy recovery projects but most are not as large as the St. Louis project and are in the early planning stages.[22] It is estimated that refuse combustion by the utility industry will increase sixtyfold (Union Electric's increase of 26 times plus a few other systems) from 1974 to 1985.

The most important factor discussed above is the shift from oil and gas to coal, and the large increase in coal consumption. Coal combustion produces much more particulate, sulfur, trace element and possibly organic emissions than natural gas. In addition, coal generally (depending on particulate or sulfur oxide control equipment and composition of specific coals and oils) produces more particulates and trace elements than oil and relatively similar or slightly higher amounts of sulfur oxides. In addition, coal combustion produces much larger amounts of solid waste and potential water pollutants. Details on the amounts of various pollutants resulting from the combustion of coal, oil, and gas have been presented in Section II.

A less significant trend is the relatively greater increase in the combustion of western coal compared to the combustion of eastern coal. The western coal regions are regions 16 to 23 as presented in Figure 32. The potential coal supply by region has been estimated for the year 1985 for a business as usual case and an accelerated development case.[14] The 1985 projected supply and actual 1974 consumption are presented in Table 131. During 1974, 88 percent of the coal consumed was eastern coal and by 1985 the available supply will be 80 to 81 percent eastern coal. The supply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NORTH CAROLINA
S.C.
TENN
MISS
LOUISIANA
FLORIDA
OKLAHOMA
TEXAS
NEVADA
NEW MEXICO
COAL FIELDS AND PRODUCING DISTRICTS
BOUNDARIES OF PRODUCING DISTRICTS DEFINED IN BITUMINOUS COAL ACT OF 1937
STATE BOUNDARIES

Figure 32. Map of the coal-producing districts of the United States

of western coal will increase by a factor of from 3 to 6 but the percentage of the total represented by western coal will only increase from 11.6 percent to 19 or 20 percent.[14]

Table 131. WESTERN COAL CONSUMPTION AND SUPPLY

	1974 consumption		1985 supply: business as usual		1985 supply: accelerated development	
	10^3 tons	Percent of total	10^3 tons	Percent of total	10^3 tons	Percent of total
Western	71,800	11.6	212,800	19.7	414,400	20.1
Eastern	599,200	88.4	887,200	80.3	1,648,600	79.9
Total	671,000	100.0	1,100,000	100.0	2,063,000	100.0

Coal reserves are commonly classified by depth (0 to 1000 ft, 0 to 3000 ft, 0 to 6000 ft) and by reliability of the estimate (measured, indicated, undiscovered) as well as by specific properties (sulfur content, coal type). The reserves most likely to be used in the next 10 years and on which the most data are available are measured and indicated in the depth range of 0 to 1000 feet. The coal reserve base is 433,900 million tons compared to the present yearly consumption of 600 to 700 million tons.[14] Bituminous coal represents 54 percent, subbituminous 38 percent, lignite 6 percent, and anthracite 2 percent of the reserves. Western coal (54 percent of the total reserves) is predominantly subbituminous (76 percent) and lignite (8 percent).

Western coals contain less ash and sulfur, more moisture, and have a lower heating value than eastern coal, as shown in Table 132. The major effect of using western coal instead of eastern coal should be a reduction in the potential SO_2 emissions per unit of fuel. Actual SO_2 emissions will depend on the actual coal mined (as only a small fraction of the reserves will be used and sulfur content varies from mine to mine) and the application of SO_2 controls. There are extensive reserves (compared to current consumption) of less than 1 percent sulfur coal in the east, but these reserves have been used primarily for coke manufacture and have been too costly for utility use.[24] The variation in ash content between eastern and western coal is not significant. Available data on the trace element content of coal[25] show wide variations (one to two orders of magnitude) within regions, and considering the limited accuracy of the data, there is no clear difference between eastern and western coal. However, data on western coal are very limited compared to other coals. The use of western coal will significantly affect the design and application of control methods, including particulate, NO_x, and SO_2 methods.

Table 132. AVERAGE PROPERTIES OF COAL RESERVE BASE[a]

	Heat content, Btu/lb		Moisture, weight %	Ash		Sulfur	
	Dry	Raw coal		Weight % dry	$lb/10^6$ Btu	Weight % dry	$lb/10^6$ Btu
Western	12,000	9,800	23	7.2	6.0	0.58	0.48
Eastern	13,300	12,600	5.7	9.6	7.2	2.4	1.9

[a] Compiled by GCA from data in reference 14.

Trends in Boiler Population

The trends to 1985 for various boiler types were also estimated and are presented in Table 133. Based on the average age of stoker-fired boilers (37 years in 1972) and the normal useful plant life of 35 to 40 years, we estimated a 50 percent decline in bituminous coal stoker-fired boilers. New source performance standards limiting NO_x emissions from bituminous coal-fired power plants to 0.7 $lb/10^6$ Btu will in effect prohibit the construction of new cyclone boilers in sizes greater than 250 x 10^6 Btu/hr, as NO_x emissions from cyclone boilers are in the range of 1.5 to 2.3 $lb/10^6$ Btu. Many cyclone boilers are relatively new (capacity average

Table 133. ELECTRIC UTILITY FUEL CONSUMPTION TRENDS TO 1985

		1974 fuel use, 10^{12} Btu	1985 fuel use, 10^{12} Btu	Percent change, 1974-1985
1.0.00.0.0	Electric Generation	15,387	22,531	+ 46
1.1.00.0.0	External Combustion	14,798	20,932	+ 42
1.1.10.0.0	Coal	8,502	16,994	+100
1.1.11.0.0	Bituminous	8,264	14,976	+ 81
1.1.11.1.0	Pulverized Dry	5,971	11,877	+ 99
1.1.11.2.0	Pulverized Wet	1,118	1,952	+ 75
1.1.11.3.0	Cyclone	1,118	1,118	+ 0
1.1.11.4.0	All Stokers	57	29	- 50
1.1.12.0.0	Anthracite	38	19	- 50
1.1.12.1.0	Pulverized Dry	13	9	- 30
1.1.12.2.0	Pulverized Wet	0	0	0
1.1.12.3.0	Cyclone	0	0	0
1.1.12.4.0	All Stokers	25	10	- 60
1.1.13.0.0	Lignite	200	2,000	+1000
1.1.13.1.0	Pulverized Dry	120	1,730	+1400
1.1.13.2.0	Pulverized Wet	30	220	+730
1.1.13.3.0	Cyclone	30	30	+0
1.1.13.4.0	All Stokers	20	20	0
1.1.20.0.0	Petroleum	3,039	2,172	- 29
1.1.21.0.0	Residual Oil	2,901	2,060	- 29
1.1.21.0.1	Tangential Firing	1,128	801	- 29
1.1.21.0.2	All Other	1,773	1,259	- 29
1.1.22.0.0	Distillate Oil	138	99	- 29
1.1.22.0.1	Tangential Firing	54	38	- 29
1.1.22.0.2	All Other	84	61	- 29
1.1.30.0.0	Gas	3,257	1,780	- 55
1.1.30.0.1	Tangential Firing	791	356	- 55
1.1.30.0.2	All Other	2,466	1,344	- 55
1.1.40.0.0	Refuse	0.6	36	+6000
1.2.00.0.0	Internal Combustion	589	1,549	+262
1.3.00.0.0	Turbine	515	1,467	+285
1.3.20.0.0	Oil	286	815	+285
1 3.30.0.0	Gas	229	652	+285
1.4.00.0.0	Reciprocating	74	82	+ 10
1.4.20.0.0	Oil	26	29	+ 10
1.4.30.0.0	Gas	48	53	+ 10

age in 1972 was 8 years) and will therefore continue to operate through 1985. It was estimated that the use of cyclone boilers would remain constant to 1985.

The increase in other bituminous coal-fired boilers was assumed to be inversely proportional to their average ages (see Table 13), and increases of 99 percent and 75 percent were calculated for pulverized dry bottom and pulverized wet bottom boilers, respectively. The population of anthracite-fired boilers will decline sharply to 1985. Since stoker-fired boilers are older, it was assumed that they would decline twice as fast as pulverized-fired boilers.

As shown in Table 130, lignite consumption by the utility industry is expected to increase 1000 percent from 1974 to 1985. In the past, small stokers have been mainly used to burn lignite, but more recently the trend has been to large pulverized coal or cyclone boilers.[27] Two new pulverized lignite dry bottom boilers with a total capacity of 1,150 MW began operation in late 1971 and early 1972. These two new boilers burned about 20 percent of the lignite in 1974. Another recently installed lignite-fired boiler is a 235 MW cyclone.[28] However, the future growth of lignite-fired cyclone type boilers may be limited by anticipated new source performance standards.[29] We estimated that the use of cyclone type boilers to burn lignite would not increase to 1985. In addition, it was estimated that the use of stoker-fired boilers would not increase as the trend is to larger boilers. Although very little data were available, we estimated that the growth rate of pulverized dry bottom boilers would be twice the rate for pulverized wet bottom.

The ages of oil-tangential-fired boilers and other oil-fired boilers were practically the same, so the same growth rates were assumed for these systems. Similarly, the ages of gas-tangential-fired boilers and other gas-fired boilers were the same, so the same growth rate was assumed for all gas-fired boilers.

INDUSTRIAL

Fuel Use Trends

As is the case for the electric utility combustion sector, the forecasting of developments in the industrial combustion sector is extremely difficult. The changing energy picture, the impact of government regulations, and the availability of clean fuels all contribute to the high degree of uncertainty involved in forecasting future development. Our evaluation of industrial fuel consumption trends indicates an increase from 1973 to 1985 of 14 percent within the categories discussed in this study. Project Independence predicts that the total industrial energy consumption (including direct heat, feedstocks and electrical energy) will increase about 27 percent, with utility generated electrical energy consumption by the industrial sector increasing nearly 100 percent based on business as usual and an $11/barrel price for imported oil. Industrial fuel consumption trends are presented in Table 134.

Table 134. DETAILED INDUSTRIAL FUEL CONSUMPTION TRENDS TO 1985

		1973 fuel use, 10^{12} Btu	1985 fuel use, 10^{12} Btu	Percent change, 1973-1985
2.0.00.0.0	Industrial	11,300	12,934	+14
2.1.00.0.0	External Combustion	8,546	10,016	+17
2.1.10.0.0	Coal	1,370	1,945	+42
2.1.11.0.0	Bituminous	1,320	1,899	+44
2.1.12.0.0	Anthracite	10	2	-80
2.1.13.0.0	Lignite	40	44	+10
2.1.20.0.0	Petroleum	1,700	2,448	+44
2.1.30.0.0	Gas	5,200	5,200	+ 0
2.1.41.0.0	Bagasse	20	23	+13
2.1.42.0.0	Wood/Bark	250	400	+60
2.2.00.0.0	Internal Combustion	2,760	2,922	+ 6
2.2.20.0.0	Petroleum	360	518	+44
2.2.30.0.0	Gas	2,400	2,400	+ 0

In the industrial sector, the use of coal will increase over 42 percent. This large increase may be attributable to the high price of oil and the limited availability of natural gas. We estimate that industrial consumption of lignite will increase only 10 percent, as several problems are involved in utilizing lignite including: limited geographical distribution of deposits (primarily in North Dakota); shipping difficulties associated with the large volume required as a consequence of the low heating value of lignite; and combustion problems (lignite ash tends to foul heat exchange surfaces). Utilities operating large power plants can afford to solve lignite distribution and combustion problems. However, lignite consumption by industrial users will be limited primarily by distribution problems from producing to consuming areas. Anthracite consumption has been declining for decades[11] and we adopted the Project Independence[12] estimate of 14 percent/year to 1985 or a total decline of 80 percent. Bituminous coal consumption will increase 44 percent with the consumption of western subbituminous coal certainly increasing at a greater rate than eastern coal. Subbituminous coal has drawbacks similar to lignite although much less severe, and these drawbacks will be compensated for by the low sulfur content. However, the increase in subbituminous coal consumption will be greater in the utility sector where unit trains and other options, such as coal slurry pipelines and plant location, can be implemented.

Petroleum consumption by the industrial sector will increase 44 percent.[7] Despite the high price of oil, many industrial consumers limited to choosing between oil and coal will select oil. Oil-fired boilers and auxiliary equipment are less expensive and easier to operate than coal-fired boilers. Small energy users will show a particularly strong preference for oil as the economics will tend to favor oil-fired equipment.

Natural gas resources are limited and a decline in industrial consumption of 5 percent from 1972 to 1985 was predicted.[7] However, consumption actually declined 5 percent from 1972 to 1973 so it was estimated that gas consumption would remain constant from 1973 to 1985.

Bagasse (a sugar cane by-product or waste material) is burned to produce steam and/or electricity. Sugar cane production has fluctuated over the past 10 years with no clear trends.[16] A growth rate of 1 percent/year for the combustion of bagasse was selected, yielding a total increase of 13 percent. Wood bark is burned extensively by the lumber and paper industry, with large amounts consumed in Washington and Oregon as well as some areas in the south. The lumber industry is expected to grow at a 4 percent rate and the paper industry at a 3.6 percent rate to 1980.[30] In addition, all available waste wood materials are not utilized and the percent utilization will probably increase.[29] A growth rate for wood bark combustion of 4 percent/year was estimated.

Specific data on fuel use trends for internal combustion equipment were not available. Overall fuel use trends were applied to the industrial internal combustion sector.

Trends in Boiler Population

The limited trend data available on those boiler characteristics considered in this project do not show definitive and significant trends. We estimate that boiler characteristics in 1985 will be similar to 1973, and the major changes will be the fuel use trends presented in Table 134. The growth of particular boiler types should be the same as the growth of the overall fuel type. Thus, industrial coal-fired boilers will continue to be predominantly pulverized (57 percent of coal consumed) and spreader stokers (36 percent of coal consumed). More than 79 percent of the coal burned in industrial boilers is burned in boilers above 100×10^6 Btu/hr capacity. These large boilers will continue to be predominantly pulverized coal-fired and spreader stokers although the prevalence of pulverized coal firing may increase slightly.[31] The smaller boilers (less than 100×10^6 Btu/hr) are primarily underfeed stokers at the present time, but there is a trend toward more spreader stokers.

COMMERCIAL/INSTITUTIONAL

Fuel Use Trends

The commercial sector consumed 12 percent of the fuel consumed by stationary combustion sources in 1973 (see Table 129). Commercial fuel was primarily oil and gas with only minor amounts of coal. Only 1.5 percent of the coal consumed was consumed by the commercial sector, and coal represented only 3.4 percent of the commercial sector fuel use. The available trend data do not distinguish between the commercial sector and the residential sector, instead both sectors are combined. Our estimates of commercial fuel consumption trends were based on the assumption that fuel trends are the same for both sectors. Commercial fuel use trends are presented in Table 135. The data are based on business as usual[7] and an $11/barrel price for imported oil.

Coal consumption by the commercial residential sector will decline 55 percent from 1973 to 1985.[7] Anthracite consumption will decline sharply in all consuming sectors. The decline in the commercial sector will be 80 percent.[12] Lignite is an extremely minor commercial fuel (representing only 0.02 percent of commercial fuel) and we estimated no change in consumption. A decline in bituminous coal consumption of 43 percent from 1973 to 1985 was estimated. The decline in coal consumption is partly attributable to the convenience of oil and gas for the many small commercial consumers of fossil fuels. However, commercial consumption of oil is predicted to decline 16 percent from 1973 to 1985.[12] Natural gas is the only commercial residential fuel that is expected to be consumed in sharply larger quantities by 1985. The change by 1985 is expected to be an increase of 47 percent.[12] Wood is a very minor commercial fuel and no change in consumption to 1985 is estimated.

Commercial internal combustion sources are primarily engines used for water pumping and possibly generating small amounts of electricity. The

Table 135. COMMERCIAL/INSTITUTIONAL FUEL USE TRENDS, 1973-1985

		1973 fuel use, 10^{12} Btu	1985 fuel use, 10^{12} Btu	Percent change, 1973-1985
3.0.00.0.0	Commercial/Inst.			+10
3.1.00.0.0	External Combustion	4450	4883	+10
3.1.10.0.0	Coal	156	70	-55
3.1.11.0.0	Bituminous	101	58	-43
3.1.11.1.0	Pulverized Dry	20	11	-43
3.1.11.2.0	Pulverized Wet	1	<1	-43
3.1.11.4.0	All Stokers	80	46	-43
3.1.12.0.0	Anthracite	55	11	-80
3.1.12.4.0	All Stokers	55	11	-80
3.1.12.6.0	Spreader Stokers	0	0	0
3.1.13.0.0	Lignite	1	1	0
3.1.13.4.0	All Stokers	1	1	0
3.1.13.6.0	Spreader Stokers	0	0	0
3.1.20.0.0	Petroleum	2379	1998	-16
3.1.21.0.0	Residual Oil	1269	1066	-16
3.1.21.0.1	Tangential Firing	10	8	-16
3.1.21.0.2	All Other	1259	1058	-16
3.1.22.0.0	Distillate Oil	1110	932	-16
3.1.22.0.1	Tangential Firing	11	9	-16
3.1.22.0.2	All Other	1099	923	-16
3.1.30.0.0	Gas	1914	2814	+47
3.1.30.0.1	Tangential Firing	82	121	+47
3.1.30.0.2	All Other	1832	2693	+47
3.1.42.0.0	Wood/Bark	1	1	0
3.2.00.0.0	Internal Combustion	50	58	+16
3.2.20.0.0	Petroleum	25	21	-16
3.2.30.0.0	Gas	25	37	+47

trends for internal combustion were estimated to be the same as the particular fuels used.

The summation of the above trends, as presented in Table 135, indicates a growth in commercial fuel consumption of 10 percent. Overall energy consumption by the commercial sector is expected to grow 40 percent, mainly due to a 260 percent increase in electric energy consumption.[7] The most significant point in the commercial fuel use trends is that only natural gas consumption will increase, and it will increase sharply (47 percent).

Trends in Boiler Population

Trends in boiler population were assumed to be the same as the fuel use trends. Data on trends for the specific categories considered in this project were not available.

RESIDENTIAL

Residential space heating has shown an annual growth rate of 3.4 percent over the period 1950 to 1968.[32] The estimated fossil fuel consumption for 1973 (Table 129) shows an increase of 15 to 20 percent from 1968 and that the historical trend has continued through 1973.

Estimated residential fuel use trends, as shown in Table 136, are based on Project Independence[7] projections for the commercial-residential sector. As previously discussed, the Project Independence estimates were based on business as usual and an $11/barrel price for imported oil. It was assumed that the fuel use growth rates were the same for both the commercial and residential sectors.

Table 136. RESIDENTIAL FUEL USE TRENDS, 1973-1985[a]

		1973 fuel use, 10^{12} Btu	1985 fuel use, 10^{12} Btu	Percent change, 1973-1985
4.0.00.0.0	Residential	8,057	9,258	+15
4.1.00.0.0	External Combustion	8,057	9,258	+15
4.1.10.0.0	Coal	192	86	-55
4.1.11.0.0	Bituminous	115	69	-40
4.1.12.0.0	Anthracite	75	15	-80
4.1.13.0.0	Lignite	2	2	0
4.1.20.0.0	Petroleum	2,280	1,026	-55
4.1.30.0.0	Gas	5,450	8,011	+47
4.1.42.0.0	Wood	135	135	0

[a] Space heating only. Trends primarily from reference 7.

Fuel use for space heating is expected to increase 15 percent from 1973 to 1985. The growth rate will be 1.2 percent/year compared to the historical growth rate of 3.4 percent/year. However, when electric energy is included, the total energy growth rate for the residential sector will be 3 percent/year,[7] which is only slightly below the historical trend. Natural gas is the major residential space heating fuel (68 percent) and its share of the residential sector will be even larger in 1985 (88 percent). Coal is only a very minor residential fuel (3 percent) and its consumption will be even less in 1985 (about 1 percent of residential fuel use). Although there has been an increased interest in the combustion of wood for space heating, we estimate that there will be no real growth in this area.

SIGNIFICANCE OF TRENDS

Changes and trends in total energy consumption and fuel use patterns have the potential to affect the amounts and types of air, water and solid waste pollutants. In addition, the trends discussed in the previous subsections will affect the design and application of combustion equipment, air pollution control methods (particulate, SO_x and NO_x) and water pollution control methods as well as solid waste practices. The actual future pollutant quantities will be strongly affected by government regulations.

The most significant trend in the overall picture is the large (87 percent) increase in coal consumption. Increased coal consumption is due to normal growth and the limited growth of oil (-2 percent) and gas (+13 percent). Coal combustion tends to generate over 50 times as much ash and most trace metals (either as an air pollutant or solid waste), about twice as much NO_x, and three times as much SO_x (based on current average levels of 1 percent sulfur oil and 2 percent sulfur coal) as oil combustion. With the exception of NO_x, pollutants generated by gas combustion are insignificant compared to those generated by coal combustion. The impact of ash emissions can be minimized by control equipment. NO_x emissions from coal can be reduced to levels associated with gas and oil. SO_x emissions can, of course, be controlled through the use of low sulfur fuels or SO_x scrubbers. Scrubbers do create potential water pollution and solid waste problems.

The significance of increased coal combustion will be amplified in the electric utility sector where coal consumption is expected to increase 100 percent while oil and gas decline sharply — 10 and 30 percent, respectively. In addition, coal represents over 50 percent of utility fuel use compared to only 25 percent of the total stationary source fuel use. The combustion of refuse will show the largest percent change (6000) but will only be of local significance, as even by 1985, it will represent less than 0.2 percent of electric utility fuel use. Practically, all electric utility plants will be subject to Federal and State air and water pollutant regulations. Air and water pollution control measures will play a large role in the design of new coal-fired power plants. The use of low sulfur western coal may reduce the apparent need for SO_2 scrubbers. However, the use of western coal may adversely affect particulate control equipment.

In the industrial sector the use of both coal and oil will increase 40-45 percent while the use of gas will remain constant. As industrial coal consumption represents only 16 percent of utility consumption, the increase will be less stringent. However, the overall shift from gas (zero growth to 1985) will be very significant, tending to increase pollutant quantities.

The majority of pollutants generated by the commercial/institutional sector will decrease as only the use of natural gas will increase. The large decrease (55 percent) in coal combustion in the commercial sector will be of minimum importance as coal is a very minor commercial fuel. Wood/bark and refuse combustion will increase and may be important in specific geographic areas.

Residential fuel use trends will be the same as commercial trends and thus the significance will be similar. However, the decrease in coal combustion may be important, as the majority of the coal is consumed in a relatively few states, and the ambient levels of organics (BaP and BSO) have correlated well with residential coal consumption trends.[33]

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SECTION VII

ON-GOING AND PLANNED ACTIVITIES

This section, summarizing on-going and planned activities, is based on a review of current EPA contracts, the use of information retrieval services, and contact with industrial and trade organizations concerned with emissions from conventional stationary combustion sources. Because of the magnitude of the task, omissions undoubtedly have occurred.

The major emphasis of previous studies dealing with the emissions assessment of combustion sources has been placed on air emissions, and their control, from electric utility plants. These air emissions and control data are, in part, embodied in the National Emissions Data System (NEDS). However, existing NEDS emission factors, while generally good to ± 25 percent for criteria pollutants, are based on limited test data generally dating back to the 1960's. Updating of these emission factors, particularly for those combustion systems which predominate, should be and is being undertaken to an increasing extent. There is also a need for expansion of NEDS to include potentially hazardous pollutant emissions, and a new data handling system (HATREMS) is being developed for this purpose.

Although combustion source test data dealing with air, water, and solid waste emissions are being collected at an ever increasing rate, most of this information is not available in a central location for further analysis. Much of it is collected by utilities or industrial firms concerned with compliance with state or federal regulations. A centralized EPA system, Source Test Data System (SOTDAT), has been developed to assemble air emission data which can be used to determine accurate emission factors for criteria or other pollutants and evaluate control device performance, but remains to be effectively implemented. A major shortcoming of this system, however, is its reliance on Source Classification Codes (SCC) to identify the combustion systems. The Source Classification Code falls short of identifying all furnace and boiler characteristics which can affect emissions.

Water emission data for most utilities and large industrial sources are available in the National Pollution Discharge Elimination System (NPDES). This information, however, is scattered throughout the various EPA regions and has not been fully assembled and analyzed. Limited information on cooling water, boiler water blowdown, and ash pond discharge is available also for electric utilities from the FPC. The FPC is also a source of information for solid waste from ash and boiler water blowdown.

Table 137 lists the organizations that were contacted for information concerning on-going and planned activities. In addition, numerous EPA contractors were contacted. The identification of on-going activities sponsored by EPA was a difficult task since only project titles were readily available. Thus, some confusion exists with regard to specific program objectives and emphasis, and some pertinent programs may not have been included. It should be noted that a good indication of participation in on-going activities can probably be made by a perusal of references provided in this text. Companies which have contributed to past programs are most likely still engaged in similar study areas, and their noninclusion within this section probably represents errors of omission.

The following discussions will highlight the present emphasis now being placed on the environmental aspects of stationary combustion sources. Companies and organizations now engaged in these activities will be identified, a brief abstract of program objectives will be presented, and

Table 137. SUMMARY OF PERSONAL COMMUNICATIONS[a]

Organization	Person contacted
1. American Boiler Manufacturers Association	William Axtman
2. American Petroleum Institute	Ernie Cotton, Walter Ulstead
3. American Society of Mechanical Engineers	Paul Goldstein
4. Babcock and Wilcox	Thomas McNary, Nick Brovitch
5. Battelle Columbus	Warren Berry
6. Battelle Northwest	Ben Johnson, Robert Dillon
7. Betz Laboratories	Joe Shuck
8. Bureau of Mines	Zane Murphy, L.L. Fanelli, Hy Schultz
9. Charles T. Main	George Krusen
10. Combustion Engineering	Paul Bryant, Peter Havitch, Fred Hauzalek
11. Edison Electric Institute	Dick Thorsell, Gordon Olsen, Bob Palladino, Steven Barusch
12. Electric Power Research Institute	Curt Yeager, Harry Kornberg, Tom Castle, Don Anson
13. Energy Research and Development Administration	Paul Jordan, Richard Corey, Howard Smith
14. Exxon Corporation	W. Bartok
15. Federal Energy Administration	
Office of Fuel Utilization	Judy Iersh, Susan Phillips, John Deane
Environmental Branch	Ken Woodcock
Resource Development	Bill Porter
Industrial Technology	Ken Freelaine
16. Federal Power Commission	Bob Jimieson, Alex Gatner
17. Foster Wheeler	Henry Phillips
18. University of Colorado	J. Kaskinen
19. University of Illinois	D. Natusch
20. University of Maryland	G. Gordon, W. Zoller
21. University of Notre Dame	T. Theis
22. Hittman Associates	Doug Harvey
23. Institute of Gas Technology	Frank Schora
24. KVB	Dick Thompson
25. Massachusetts Institute of Technology	L. Glicksman, Dr. Harleman, Dr. Jirka
26. National Academy of Sciences	Henry Borger (Ind. Boilers), Bob Crozier (Utilities), Earl Evans, Ted Schad (Env. Studies)
27. National Coal Association	Joe Mullens
28. NUS Corporation	D.E. Simon
29. Oak Ridge National Laboratory	Bill Fulkerson
30. Saratoga Associated	Dan Kozcik (Power Plant Siting)
31. Tennessee Valley Authority	B.G. McKinney, Bill Fulkerson
32. U.S. Environmental Protection Agency	
Office of Solid Waste Management, Washington, D.C.	Robert Lowe, Marsha Evarston, D. Sussman, Robert Holloway
Office of Planning and Management, Washington, D.C.	Jim Spire
IERL, Research Triangle Park, N.C.	Robert Hall, Les Sparks
Thermal Pollution Section, Corvallis, Oregon	Frank Rainwater
Hazardous Waste Research Laboratory, Cincinnati	Mike Roulier
SOTDAT	Greg Bujewski
Source Testing	Ed McCauley

[a] This table is a summary of organizations and people contacted during this project as part of the effort of outlining new projects as well as the effort to obtain recent research and development data. Additional organizations were contacted and are mentioned throughout the report. GCA/Technology is in continual contact with many EPA personnel and EPA contractors, and trade organizations, and did not list all these people

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the responsible personnel involved will be identified whenever possible. Discussions are presented for the following areas of activities which include all the major unit operations contributing to emissions:

- Combustion
- Flue Gas Emissions
  - General
  - Particulate
  - Criteria Pollutants (Gases)
  - Polycyclic Organic Materials
  - Trace Elements
- Ash Handling
- Cooling Systems
- Boiler Water Treatment
- Fuels and Fuel Handling
- Flue Gas Desulfurization
- Particulate Control Devices.

Many programs, of course, are concerned with several of the areas listed. These programs are included in a general category or are listed in what was felt to be the area of most significant interest.

COMBUSTION

Activities in the combustion area are concerned with the design of new furnaces, boilers, or internal combustion engines, or the modification of existing units to improve combustion efficiency, lower pollutant levels, or to allow the burning of different fuels. An improvement in combustion efficiency can either reduce pollutant emissions (e.g., HC, CO, POM) or increase them (e.g., NO_x).

The design of combustion units is an activity that is largely carried out by industrial manufacturers or trade organizations such as the Electric Power Research Institute, the American Gas Association, the

American Petroleum Institute, etc. However, their activities are to some extent directed by existing and proposed emission regulations which have been responsible, for example, for many developments in the design of combustion units to meet NO_x regulations.

Many of the programs are concerned with the use of synthetic fuels (solvent refined coal, low or high Btu gas, etc.) through the design of advanced combustors or the modification of existing units. Others are concerned with new combustion concepts such as magnetohydrodynamic power generation. These aspects of combustion are not included in Table 138, which lists on-going and planned conventional combustion studies, the supporting agency and contractor, the project manager, and a brief abstract of the program. Additional combustion studies, aimed at control of specific pollutants, will also be found in other appropriate subsections.

Table 138. ON-GOING AND PLANNED ACTIVITIES: COMBUSTION

Title:	Boiler Firing Test with Coal/Oil Emulsion
Contract No.:	RP 527
Supporting Organization:	EPRI
Performing Organization:	General Motors
Principal Investigator:	Unknown
Project Description:	The objective of this 1-year project is to test an 80,000 lb/hr steam plant, firing a coal/oil emulsion fuel. The test will assess the stability of the fuel, thermal performance, stack emissions, ash removal, fouling and slagging characteristics, and economic feasibility.

Title:	Engineering Evaluation of Atmospheric Fluidized Bed Combustion (AFBC)
Contract No.:	RP 412
Supporting Organization:	EPRI
Performing Organization:	Babcock and Wilcox
Principal Investigator:	Unknown
Project Description:	The objective of this 16-month program is to evaluate the adequancy of available information for commercialization of the AFBC process. The program includes a study of existing designs of uitlity boilers using FBC.

Title:	Boiler Combustion Modifications
Contract No.:	68-02-1415 (EPA), RP 200 (EPRI)
Supporting Organization:	EPA and EPRI
Performing Organization:	Exxon Research and Engineering Company
Principal Investigator:	W. Bartok
Project Description:	U.S. Environmental Protection Agency and EPRI are jointly funding a program to determine the effectiveness of combustion modification techniques to control pollutant emissions from utility boilers. Pollutants of interest are oxides of nitrogen, sulfur dioxide, hydrocarbons, carbon monoxide, and combustible and noncombustible particulates. The project will be completed by May 1977.

Table 138 (continued). ON-GOING AND PLANNED ACTIVITIES: COMBUSTION

Title:	Advanced Gas Turbine Development
Contract No.:	RP 359
Supporting Organization:	EPRI (D. Texeira)
Performing Organization:	Solar Div. of International Harvester
Principal Investigator:	Unknown
Project Description:	This 15-month program will develop a combustion process for conventional fuels to minimize formation of NO_x, carbon monoxide, and unburned hydrocarbons from gas turbines while maintaining satisfactory performance parameters. Scheduled to be completed by June 1976.

Title:	Gas Turbine-Steam Boiler Repowering
Contract No.:	RP 528
Supporting Organization:	EPRI (D. Texeira)
Performing Organization:	Westinghouse Electric Corporation
Principal Investigator:	Unknown
Project Description:	Results of this 1-year project will include heat balances, required modifications, and cost estimates for a representative (ca. 300 MW) steam boiler. Principal fuels to be treated in the study are natural gas and fuel oil. Several plants utilizing the heat in gas turbine exhaust gases have been constructed and operated for over 10 years. However, these plants were "grass roots" installations, and not repowered systems. The utilization of the hot turbine exhaust (ca. 1000°F) in retrofit applications poses unique problems. NO_x reduction is expected. Scheduled to be completed by August 1976.

Title:	Effects of Mixing on Kinetic Processes in Pulverized Coal Combustion
Contract No.:	RP 364
Supporting Organization:	EPRI (R. Carr)
Performing Organization:	Brigham Young University
Principal Investigator:	Dr. L. D. Smoot

Table 138 (continued). ON-GOING AND PLANNED ACTIVITIES: COMBUSTION

Project Description:	This 38-month project will employ a small laboratory combustor to determine the effect of turbulent mixing on the kinetics of pulverized coal and char combustion at atmospheric pressure. Scheduled to be completed by December 1977.
Title:	Combustion Dynamics as Related to Air Pollution
Contract No.:	BR - 26 - 1
Supporting Organization:	AGA
Performing Organization:	University of Michigan
Principal Investigator:	Unknown
Project Description:	An analytical and experimental study of pollutants resulting from the combustion of natural gas.
Title:	Design and Scale-Up of Low Emission, High Efficiency Boilers
Contract No.:	68-02-1488
Supporting Organization:	U.S. EPA (G. B. Martin)
Performing Organization:	Ultra Systems Inc.
Principal Investigator:	M. Heap
Project Description:	
Title:	Combustion Process Analysis
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	University of Wisconsin
Principal Investigator:	H. K. Newhall
Project Description:	Work related to NO_x and particulate formation in diffusion flames.

Table 138 (continued). ON-GOING AND PLANNED ACTIVITIES: COMBUSTION

Title:	Field Testing - Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers
Contract No.:	68-02-1074
Supporting Organization:	U.S. EPA (R. E. Hall)
Performing Organization:	KVB Engineering, Inc.
Principal Investigator:	G. A. Cato, D. R. Bartz, C. Devito, B. G. Morton, and L. J. Muzio
Project Description:	A determination of NO_x and other pollutants emitted by industrial boilers and a study of control measures through testing of about 70 boilers.

FLUE GAS EMISSIONS - GENERAL

This subsection discusses programs which involve the characterization of flue gas emissions in general from combustion sources rather than emphasizing the measurement of a specific pollutant. An attempt has been made to determine the thrust of specific programs and to list them under appropriate pollutant subsections. The programs listed in Table 139 are studies which involve an overall characterization of emissions, including in many cases hazardous and trace material.

Table 139. ON-GOING AND PLANNED ACTIVITIES:
FLUE GAS EMISSIONS - GENERAL

Title:	Systems Evaluation of the Use of Low Sulfur Western Coal in an Existing Small and Intermediate Size Boilers
Contract No.:	68-02-1863
Supporting Organization:	U.S. EPA (D. G. Lachapelle)
Performing Organization:	KVB Engineering Inc.
Principal Investigator:	K. L. Maloney
Project Description:	KVB will survey and compile information on small and intermediate size boilers, emphasizing those that can burn western coal. Detailed emissions and performance tests will be conducted on selected boiler/fuel combinations including both eastern and western coal. Scheduled completion is October 1977.

Title:	Stationary Source Assessment Documents
Contract No.:	68-02-1320
Supporting Organization:	U.S. EPA
Performing Organization:	Monsanto Research Corporation
Principal Investigator:	Unknown
Project Description:	In-depth environmental assessment on air emissions from combustion and other sources.

Title:	Modeling of Air Quality Impact of Selected Power Plants
Contract No.:	68-02-1480
Supporting Organization:	U.S. EPA (Mears)
Performing Organization:	Walden Research, A Division of Abcor
Principal Investigator:	P. Morgenstern
Project Description:	

Table 139 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - GENERAL

Title:	Field Testing of Industrial Sources
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Monsantc Research Corporation
Principal Investigator:	W. R. Feairheller
Project Description:	This 3-year program involves the testing of 28 or more sources for mercury, acid mist, fluoride or lead and many gaseous materials.

Title:	Domestic and Commercial Heating
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	EPA, IERL, RTP
Principal Investigator:	R. E. Hall
Project Description:	A study of the effect of operational variables and boiler components to determine particulate and NO_x emissions from residential and commercial heating equipment using oil or gas as a fuel. A complete investigation will be made of boiler types, burners, and fuels used in commercial heating to select typical units for future testing.

Title:	Characterization and Control of Air Pollutant Emissions from Combustion of Fuels
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	EPA, IERL, RTP
Principal Investigator:	G. B. Martin
Project Description:	A 5-year study of air pollutants from all fuels and their potential for control using appropriate combustors under controlled laboratory conditions.

Table 139 (continued). ON-GOING AND PLANNED ACTIVITIES:
FLUE GAS EMISSIONS - GENERAL

Title:	Effluents from Coal-Fired Power Plants and Their Interaction with the Atmosphere
Contract No.:	RP 330
Supporting Organization:	EPRI
Performing Organization:	University of Washington
Principal Investigator:	Unknown
Project Description:	A 3-year program to characterize emissions from the Centralia, Washington, 1400 MW coal-fired power plant. Stack and plume measurements of particulates (particle size) and gaseous pollutants.
Title:	Determination of the Feasibility of Ozone Formation in Power Plant Plumes
Contract No.:	RP 572
Supporting Organization:	EPRI
Performing Organization:	Meteorology Research, Inc.
Principal Investigator:	Unknown
Project Description:	This 8-month project will determine the extent of ozone formation in power plant plumes. Research will include a literature survey, airborne plume monitoring at several coal- and gas-fired power plants in dry and humid regions of southern and southwestern United States, and development and validation of a plume chemistry computer model.
Title:	Atmospheric Dispersion and Interaction of SO_2, H_2SO_4, NO_x, O_3 and Particulates of Stack Emissions from Coal-Fired Power Plants
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	TVA
Principal Investigator:	T. L. Montgomery
Project Description:	A Study of emissions as determined by plant operations and the changes in composition which occur as a function of time.

Table 139 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - GENERAL

Title:	Fossil Fuels, General Combustion, Environmental
Contract No.:	
Supporting Organization:	Exxon Corporation
Performing Organization:	Exxon Corporation
Principal Investigator:	N. Alpert
Project Description:	R&D leading to novel processes and techniques for cleaner combustion of fossil fuels. Includes control of SO_x, NO_x, particulates, noise, odor, etc.
Title:	Technology Assessment and Planning Support
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Aerospace Corporation
Principal Investigator:	J. Meltzer
Project Description:	Characterization of emissions from sources and their relevant control technology, evaluate their effect on ambient air quality and identify control technology gaps.
Title:	Emissions from Major Air Pollution Sources and Their Atmospheric Interactions
Contract No.:	
Supporting Organization:	U.S. National Science Foundation
Performing Organization:	University of Maryland
Principal Investigator:	G. E. Gordon
Project Description:	

FLUE GAS EMISSIONS - PARTICULATES

The measurement of particulate emissions from electric utilities has been an active area for many years and the data reported is probably good to within ± 25 percent despite variations in test procedures. The present activity is being carried out by many testing and utility firms interested in compliance testing. EPA is also conducting or sponsoring test programs aimed at evaluating the effects of fuel, boiler design, and control device performance. In recent years the emphasis has shifted from the measurement of total particulate to a determination of fine particle distributions and the emissions of potentially hazardous trace metals and organic materials. The interest in fine particulates basically stems from their respirable nature and the tendency of many hazardous species to be concentrated in the fine particle fraction. Activities dealing with these hazardous emissions will be discussed later in appropriate subsections.

An extensive analysis of particulate emissions has been carried out by Midwest Research Institute (MRI). At the time of the initial study, MRI estimated that most particle size data had been obtained by techniques unsuitable for sampling and sizing particulates below 2 microns in diameter. Accordingly, it was necessary to extrapolate data for large particles down to the size range of fine particulates. A subsequent revision of this study is based on recent tests using cascade impactors to determine size distributions and the fractional efficiency of control devices down to about 0.2 microns. Recent and on-going studies have adopted the use of impactors to determine fine particulates, and several companies including SRI, KVB, and GCA have used condensation nuclei counters to measure particles as small as 0.01 micron diameter.

EPA at Research Triangle Park is currently undertaking studies aimed at the overall fine particulate problem, including health effects, formation and transformation, source identification, measurement, and control. Proposed activities involve further characterization of emissions from combustion sources and the evaluation of novel control devices.

Although somewhat beyond the scope of this program, there is a strong interest now in the behavior (and formation) or particulates leaving the stack. Plume reactions and subsequent transformation and transport phenomena are now being studied by several research organizations. Aircraft are being used by organizations such as Washington University, St. Louis, Missouri, and Brookhaven National Laboratories, New York, to monitor emissions downwind of a coal-fired utility boiler and an oil-fired utility boiler stack, respectively.

Current programs dealing with particulates are listed in Table 140. This listing is a brief one, since many of the current activities are to be found in preceding subsections and in subsequent subsections dealing with trace elements, POM, and control devices.

Table 140. ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - PARTICULATES

Title:	Development of an In-Stack Impactor/Precipitator for Sizing Submicron Particles
Contract No.:	RP 463
Supporting Organization:	EPRI
Performing Organization:	Meteorology Research, Inc.
Principal Investigator:	Unknown
Project Description:	Development of an electrostatic impactor with a particulate size analysis range from 0.03-30 microns would serve at least two functions. It would enable utilities to completely characterize the fly ash emissions at a specific site, thereby eliminating some of ~~the~~ guesswork in purchasing particulate cleanup devices. Also, it would permit the characterization of particulate removal devices at the time of checkout to ensure that the devices meet system guarantees. Scheduled to be completed by March 1976.
Title:	Particle Formation in High Temperature Systems
Contract No.:	
Supporting Organization:	Public Service Co. of New Hampshire
Performing Organization:	University of New Hampshire
Principal Investigator:	G. D. Ulrich
Project Description:	A correlation of fly ash properties from commercial coal- and oil-fired boilers as a function of fuel composition and time-temperature history.

FLUE GAS EMISSIONS - SULFUR OXIDES

There is general agreement that almost all (~90 percent) of the sulfur contained in the fuel is emitted from the stack. This is generally true for all fuels with the exception of some high mineral content fuels such as certain lignites which can bind and retain up to 50 percent of the sulfur in the ash. Therefore, the emphasis has been on research to either eliminate the sulfur prior to combustion or to control its emissions by flue gas desulfurization.

There is general agreement that most of the sulfur oxides emitted are largely SO_2 (~98 percent). However, some SO_3 is emitted directly. In general, the leaner the fuel mixture, the more SO_3 is formed. SO_3 formation is also a function of boiler design and method of firing. Smaller furnaces, such as those used in the commercial and residential sectors, emit more SO_3 relative to SO_2 than do larger size installations. The reported emissions of SO_3 are reportedly higher for oil than for coal, and oil combustion has been postulated as a major source of acid mist which is found in high concentrations in the oil-burning eastern states. The importance of SO_3 emissions is highly speculative since the entire question of SO_2 atmospheric transformation and transport is still largely unresolved. Further work in this area is needed. Instrumentation and measurement techniques for SO_2, sulfates and sulfuric acid are areas also requiring additional study.

Table 141 lists a few pertinent studies with only one involving the determination of sulfur distribution within a power plant.

Table 141. ON-GOING AND PLANNED ACTIVITIES:
FLUE GAS EMISSIONS - SO_x

Title:	Sulfur Balance Study
Contract No.:	
Supporting Organization:	New York Electric and Gas Corporation
Performing Organization:	Battelle Memorial Institute
Principal Investigator:	Unknown
Project Description:	A study to determine sulfur losses in a coal-fired power plant. Sulfur losses will be determined during pulverized coal firing and distributions determined in fly ash, bottom ash, and fireside deposits.

Title:	Sulfur Dioxide Oxidation Rate in Oil-Fired Power Plant Plumes
Contract No.:	RP 382
Supporting Organization:	EPRI
Performing Organization:	State University of New York, Albany
Principal Investigator:	Unknown
Project Description:	The oxidation of SO_2 on solid surfaces will be studied in the laboratory, using molecular beam techniques. Reaction products and rates will be determined by mass spectrometry and Auger spectroscopy on a variety of well-characterized surfaces. Pure metal/metal oxides, and eventually carefully studied fly ash from oil-fired power plants will be used.

Title:	Preliminary Assessment of Sulfate Emissions from Space Heating and Other Small Combustion Devices
Contract No.:	RP 574
Supporting Organization:	EPRI
Performing Organization:	KVB Engineering Inc.
Principal Investigator:	Unknown

Table 141 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - SO_x

Project Description:	The primary task of this 4-month project is to measure sulfur dioxide and sulfates in flue gases of operating residential space heating and other small boilers in New York City. In addition, a limited literature survey on sulfur oxide conversion mechanisms in fossil-fueled boilers and examination of sulfur dioxide and sulfate data in New York City for the last 10 years will be performed.
Title:	Interaction of Sulfuric Acid Mist and Nitrogen Dioxide
Contract No.:	RP 201
Supporting Organization:	EPRI, National Coal Association
Performing Organization:	Hazelton Laboratories, Inc.
Principal Investigator:	Unknown
Project Description:	For several years Hazelton Laboratories, Inc. has been conducting a study to determine the physiological effects on monkeys and guinea pigs of various concentrations of sulfur dioxide, sulfuric acid mist, and fly ash, and their mixtures. This recent effort addresses the possible interaction between sulfuric acid mist and nitrogen dioxide. Since these two pollutants rarely occur at levels known to be hazardous to humans, reported detrimental effects in humans may be due to combined action of the pollutants.

FLUE GAS EMISSIONS - NO_x

The reduction of NO_x emissions from combustion sources is an active area of study. Programs are underway in such areas as collecting basic kinetic data concerning fuel conversion and decomposition effects, boiler modification and variation in operating parameters (staged combustion, low excess air, flue gas recirculation, etc.) on emissions, and noncombustion control measures such as catalytic stack gas removal, scrubbing, and alternatives to water injection (turbines). Table 142 lists some of these projects.

Table 142. ON-GOING AND PLANNED ACTIVITIES:
FLUE GAS EMISSIONS - NO_x

Title:	Bench Scale Studies of New Scrubbing Techniques for the Abatement of NO_x
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	U.S. EPA
Principal Investigator:	L. H. Garcia
Project Description:	The objective is to screen a variety of processes for the abatement of NO_x emissions
Title:	Analysis of Flue Products from Gas-Fired Appliances
Contract No.:	EP-1-23
Supporting Organization:	AGA
Performing Organization:	AGA
Principal Investigator:	P. E. Suney
Project Description:	Development of burner designs to minimize flue gas emissions. Measurements of gas emissions are being obtained for a variety of furnace and burner designs.
Title:	Measuring the Environmental Impact of Domestic Gas-fired Heating Systems
Contract No.:	EP-94-1
Supporting Organization:	AGA
Performing Organization:	The Research Corporation of New England
Principal Investigator:	
Project Description:	A measurement and diffusion modeling study of gas-fired home heating systems, largely dealing with NO_x emissions.

Table 142 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - NO_x

Title:	Reduction of Nitric Oxide with Metal Sulfides
Grant No.:	R-800682
Supporting Organization:	U.S. EPA
Performing Organization:	Montana State University
Principal Investigator:	Dr. F. P. McCandless
Project Description:	Investigation of reaction kinetics of nitric oxides with metal sulfides to determine those most effective in nitric oxide removal.
Title:	Analysis of Test Data for NO_x Control of Utility Boilers
Grant No.:	R-802366
Supporting Organization:	U.S. EPA (R. E. Hall)
Performing Organization:	Aerospace Corporation
Principal Investigator:	D. Dykema
Project Description:	A program to correlate gas- and oil-fired boiler operation with NO_x and other emissions and to determine the effect of NO_x control measures on combustion.
Title:	Estimation of Combustion and Nitric Oxide Kinetics
Grant No.:	R-800798
Supporting Organization:	U.S. EPA (S. Lanier)
Performing Organization:	Stanford Research Institute
Principal Investigator:	R. Shaw
Project Description:	Theoretical study of NO_x formation mechanisms and kinetics.

Table 142 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - NO_x

Title:	Aerodynamic Control over Emissions of Nitrogen Oxides and Other Pollutants from Fossil Fuel Combustion
Contract No.:	68-02-0216
Supporting Organization:	U.S. EPA (D. C. Lachapelle)
Performing Organization:	Institute of Gas Technology
Principal Investigator:	D. H. Larson
Project Description:	A 5-year study to minimize NO_x emissions from gas-fired boilers while maintaining system efficiency.

Title:	Evaluation of the Effectiveness of Fuel Additives in Reducing Emissions in Coal and Oil Combustion
Contract No.:	68-02-0262
Supporting Organization:	U.S. EPA (W. S. Lanier)
Performing Organization:	Battelle Memorial Institute
Principal Investigator:	D. W. Locklin, R. D. Giammar
Project Description:	The objectives of this program are to assess the effectiveness of fuel additives in reducing emissions, to assess the potential to improve thermal efficiency, and to determine the effect of fuel and combustion conditions on emissions of polycyclic organic materials.

Title:	Pilot Field Test Program to Study Methods of NO_x Formation in Tangentially Coal-Fired Steam Generating Units
Contract No.:	68-02-1367
Supporting Organization:	U.S. EPA (D. G. Lachapelle)
Performing Organization:	Combustion Engineering Inc.
Principal Investigator:	A. Selker
Project Description:	An evaluation of NO_x reduction methods followed by experimental measurements on a modified pilot plant unit.

Table 142 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - NO_x

Title:	Investigation to Determine the Effects of Design and Operating Variables on NO_x Formation in Coal-Fired Furnaces
Contract No.:	68-02-0634
Supporting Organization:	U.S. EPA (D. G. Lachapelle)
Performing Organization:	Babcock & Wilcox Company
Principal Investigator:	W. L. Sage
Project Description:	Experimental study (5 years) to reduce NO_x emissions from wall-fired coal boilers.
Title:	Control of NO_x Formation in Wall-Fired Coal Utility Boilers
Contract No.:	Interagency Agreement (IAG) - 137D
Supporting Organization:	U.S. EPA (D. G. Lachapelle)
Performing Organization:	U.S. Tennessee Valley Authority
Principal Investigator:	J. Hollinden
Project Description:	The purpose of this study is to investigate biased firing techniques and their effects on NO_x emissions, boiler corrosion, slagging, thermal efficiency, and operational performance.
Title:	Research Initiation - Nitric Oxide Formation in Pulverized Coal Flames
Contract No.:	
Supporting Organization:	National Science Foundation
Performing Organization:	Purdue University
Principal Investigator:	N. M. Laurendeau
Project Description:	A study of the physical and chemical mechanisms controlling NO_x formation in coal burners.

Table 142 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - NO_x

Title: Catalysis Studies Directed Towards the Reduction of Nitrogen Oxides, Sulfur Dioxide, and CO Emissions from Stationary Sources
Contract No.:
Supporting Organization: University of Southern California
Performing Organization: University of Southern California
Principal Investigator: J. M. Whelan
Project Description:

Title: Nitric Oxide Reduction Test - Reeves, Person and San Juan Station
Contract No.:
Supporting Organization:
Performing Organization: Public Service Company of New Mexico
Principal Investigator: J. Grossman
Project Description:

Title: Catalytic Reduction of Nitrogen Oxides
Contract No.: BR-96-2
Supporting Organization: AGA
Performing Organization: University of California
Principal Investigator:
Project Description: A study of the reduction of NO_x with reductants, such as NH_3, CO, and hydrocarbons on catalysts.

Table 142 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - NO_x

Title:	Organic Nitrogen Compound Contribution to NO_x in Flat Flames
Contract No.:	RP 223
Supporting Organization:	EPRI
Performing Organization:	University of California, Berkeley
Principal Investigator:	Unknown
Project Description:	The major goals of this effort by the University of California, Berkeley, are to determine: (1) the mechanism of conversion of certain fuel-bound nitrogen compounds to oxides of nitrogen; (2) the percentage of organic nitrogen converted to NO_x; and (3) the fate of nitrogen that is not converted to NO_x. Expected to continue through 1977.
Title:	Determination of the Effects of Low NO_x Firing on the Corrosion, Slagging, and Other Operational Aspects of a Utility Boiler Firing Western Coal
Contract No.:	RP 529
Supporting Organization:	EPRI
Performing Organization:	Arizona Public Service Company, KVB Engineering Inc.
Principal Investigator:	Unknown
Project Description:	EPRI will sponsor a 1-year program to evaluate any of the potential side effects resulting from low NO_x fuel-rich firing techniques on low sulfur western coal. The program intent is to study the long-term effects of NO_x control on one of the 755 MW Babcock & Wilcox units at the Four Corners Power Plant in Farmington, New Mexico. Several wall tube test sections will be installed in the unit, and tube wall thickness measurements made prior to initiation of fuel-rich firing and after several months of low NO_x operation. Scheduled to be completed by March 1976.

Table 142 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - NO_x

Title:	Effectiveness of Gas Recirculation into the Combustion Air for Reducing NO_x on a Large Coal-Fired Utility Boiler
Contract No.:	RP 530
Supporting Organization:	EPRI
Performing Organization:	KVB Engineering Inc., Allegheny Power, B & W
Principal Investigator:	Unknown
Project Description:	This 3-month program will determine the feasibility of utilizing windbox gas recirculation as a NO_x reduction technique on coal-fired utility boilers. This will provide insight into alternative methods of fuel-rich firing techniques for meeting New Source Performance Standards of 0.7 lb/10^6 Btu for coal-fired boilers. The program will also determine if fuel-rich firing NO_x reduction techniques can be enhanced with gas recirculation and will expose any operational problems that may result. Scheduled to be completed by December 1975.

Title:	Field Testing: Application of Combustion Modification to Control NO_x Emissions from Power Generation
Contract No.:	68-02-1415 (EPA), RP 200 (EPRI)
Supporting Organization:	U.S. EPA (R. E. Hall) and EPRI (R. Carr)
Performing Organization:	Exxon Research and Engineering Company
Principal Investigator:	W. Bartok
Project Description:	Basically a long-term corrosion test on eastern coal using NO_x reduction processes.

Table 142 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - NO_x

Title:	Oxides of Nitrogen Decomposition in Reducing Environments
Contract No.:	RP 461
Supporting Organization:	EPRI
Performing Organization:	KVB Engineering Inc.
Principal Investigator:	Unknown
Project Description:	An alternative to processes that limit the formation of NO_x are processes that lead to the destruction of NO_x, usually, in the past, by means of catalytic devices. Recent laboratory tests, however, have documented the occurrence of NO_x decomposition without catalytic materials present. Although application of the technique to full-scale systems is still far off, the results to date are encouraging. Scheduled to be completed by January 1976.
Title:	Fate of Fuel Nitrogen in Backmixed Combustion
Contract No.:	RP 241
Supporting Organization:	EPRI
Performing Organization:	Washington State University
Principal Investigator:	Unknown
Project Description:	In a 1-year study, Washington State University will investigate the degree of conversion of various fuel-bound nitrogen compounds to oxides of nitrogen in a well-stirred laboratory combustion reactor. Scheduled to be completed by September 1975.

FLUE GAS EMISSIONS - HYDROCARBONS AND CARBON MONOXIDE

Table 143 lists three EPA projects dealing with hydrocarbons. The hydrocarbons (except for polycyclic organic materials) emitted from stationary combustion sources do not make a large contribution to ambient hydrocarbon levels and are not considered a problem. Stationary combustion sources are also minor sources of carbon monoxide. Most programs dealing with NO_x reduction by combustion modifications will measure hydrocarbons and carbon monoxide since some modifications (e.g., low excess air) will tend to reduce combustion efficiency and raise hydrocarbons and carbon monoxide emission levels.

Table 143. ON-GOING AND PLANNED ACTIVITIES:
FLUE GAS EMISSIONS -
HYDROCARBONS AND CARBON MONOXIDE

Title:	Development of Methodology to Determine Organic Composition of Particulates
Contract No.:	
Supporting Organization:	
Performing Organization:	U.S. EPA
Principal Investigator:	Dr. E. Sawicki
Project Description:	

Title:	Laboratory Analysis of Nonmetallic Elements in Particulates
Contract No.:	
Supporting Organization:	
Performing Organization:	U.S. EPA
Principal Investigator:	J. D. Mulik
Project Description:	

Title:	Sampling System for Organic Products of Combustion
Contract No.:	RP 383
Supporting Organization:	EPRI
Performing Organization:	Battelle, Columbus Lab.
Principal Investigator:	Unknown
Project Description:	This 4-month project will develop a simple and efficient sampling device for the collection of organic components of stack gases from combustion sources.

FLUE GAS EMISSIONS - POM

In addition to the new or continuing projects cited in Table 144, there are other EPA investigations now underway to determine the vapor phase and particulate emissions of POM (and PHH) from stationary sources. These include work being conducted by Monsanto Research Corporation (MRC) for preparation of stationary source assessment documents, a recently completed study of "Hazardous Emission Characterizations of Utility Boilers by Midwest Research Corporation" (EPA-650/2-75-066), and the Great Northern Plains Study of western coal-fired boilers (Radian Corporation). Midwest Research Corporation (MRC) is also conducting a field evaluation of a sampling procedure for POM emission measurements from stationary sources (EPA Contract No. 68-02-2203). Battelle, KVB Engineering, Meteorology Research, Inc., and others are active in this area.

A number of long-term studies dealing with the analysis of POM compounds are being conducted at EPA-RTP, with C. Golden, J. Sigsby, and Dr. E. Sawicki listed as principal investigators.

No specific references to the measurement of POM from small residential and commercial systems have been found other than some earlier laboratory studies by Battelle and some work by KVB Engineering described previously.

Table 144. ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - POM

Title:	Instrumentation and Methodology for Assay of Individual Polynuclear Aromatic Hydrocarbons
Contract No.:	68-02-0653
Supporting Organization:	U.S. EPA
Performing Organization:	Exxon Research and Engineering Company
Principal Investigator:	R. A. Brown
Project Description:	A study to develop instrumentation and methodology for several POM compounds.
Title:	A Study of Fine Particulate Sulfates and Polycyclic Organics
Contract No.:	68-02-0752
Supporting Organization:	U.S. EPA
Performing Organization:	Battelle Memorial Institute, Columbus Lab.
Principal Investigator:	W. Henry
Project Description:	A study of the chemical composition of respirable particulates.
Title:	Matrix Isolation Analysis of Pollutant Emissions from Coal Conversion and Utilization Processes
Contract No.	RP 332
Supporting Organization:	EPRI
Performing Organization:	University of Tennessee
Principal Investigator:	Unknown
Project Description:	The class of chemical compounds known as polycyclic organic matter (POM) presents many difficult analytical problems. Various combinations of spectroscopic techniques coupled with matrix isolation will be investigated as an analytical tool to determine if samples can be characterized with less extensive preparation than is currently required.

Table 144 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - POM

Title:	Development of Sampling Procedures for POM and PCB
Contract No.:	68-02-1255
Supporting Organization:	U.S. EPA
Performing Organization:	Langston Laboratories
Principal Investigator:	T. S. Herman
Project Description:	A program to design and test manual sampling procedures for both POM and PCB.

FLUE GAS EMISSIONS - TRACE ELEMENTS

Recently a great deal of emphasis has been placed on the determination of trace elements resulting from combustion of fossil fuels. The variations in fuel composition and problems encountered in sampling and analysis of trace elements present significant difficulties. Recent and on-going activities have emphasized the material balance approach, requiring the sampling and analysis of input fuel and effluent streams, bottom and fly ash. Organizations active in this area in recent years, in addition to EPA, have included: the Tennessee Valley Authority; the Universities of Illinois, Colorado, Maryland, and West Virginia; the Bureau of Mines; MRC; MRI; KVB; Battelle; GCA; Radian; and other government contractors. The general consensus of opinion by those presently active in this area is that air emissions from combustion sources do not add significant quantities of most trace elements to the atmosphere. Only beryllium was cited in a recent Midwest Research Institute Report (EPA Contract No. 68-02-1324, Task Order No. 27) as potentially significant. However, the observed enhancement of many trace elements in the fine particle fraction of fly ash, while not significant in terms of the total mass distribution of trace elements, may pose health hazards due to the respirable nature of fine particulates. The control of fine particulates and certain volatile elements; e.g., mercury, selenium, etc., will require the development of more efficient control devices. Control may be important, also, from the standpoint of plume and atmospheric transformation processes, such as minimizing the catalytic transformation by metals (e.g., vanadium) of SO_2.

The changing energy picture has increased the interest in the trace element area because of the trend to greater use of coal. As a result, tests have been conducted on boilers burning eastern coal and are now being conducted in the Great Northern Plains study on two subbituminous-fired units and one lignite-fired unit by Radian Corporation. Fuel switching also will affect control device performance due to changes in fly ash resistivity.

Combustion system type will also influence emissions, including trace element emissions. Consideration should be given to the importance of combustion system type in the design of future experimental programs. Table 145 lists some on-going projects.

Table 145. ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - TRACE ELEMENTS

Title:	Environmental Pollutants from Electric Power Generation Facilities
Contract No.:	
Supporting Organization:	U.S. Energy Res. & Dev. Admin.
Performing Organization:	University of California
Principal Investigator:	R. E. Ragaini, D. Jones, E. Morimoto, R. Ralston, D. Garvis
Project Description:	A study of the environmental impact (trace metal emissions) of coal-fired power stations and nuclear power stations (radionuclides).
Title:	Trace Elements
Contract No.:	
Supporting Organization:	Southern California Edison Co.
Performing Organization:	Southern California Edison Co.
Principal Investigator:	J. B. Moore
Project Description:	Identification of concentration of trace elements leaving the stack of fossil-fueled plants as well as the concentration of elements in bottom ash, precipitator ash, etc. Development of control methods if required, include prevention of leaching from ash.
Title:	Trace Elements in Combustion Systems
Contract No.:	RP 122
Supporting Organization:	Electric Power Research Institute
Performing Organization:	Battelle Memorial Institute
Principal Investigator:	A. Levy and R. W. Coutant
Project Description:	A determination of the concentration of trace elements in boiler slag, precitator ash, and in fly ash and flue gas for four coals and one oil. This will be done in the Battelle furnace facility.

Table 145 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - TRACE ELEMENTS

Title:	Trace Elemental Analysis by Means of Heavy Particle-Induced X-rays
Contract No.:	
Supporting Organization:	International Atomic Energy Agency
Performing Organization:	International Atomic Energy Agency
Principal Investigator:	Dr. S. Johansson, T. B. Johansson, R. Akselsson, M. Ahlberg, and K. Malmovist
Project Description:	

Title:	To Conduct Research Relating to Toxic Metals in Atmospheric Aerosols
Contract No.:	
Supporting Organization:	Louis & Maud Hill Family Foundation
Performing Organization:	Oregon Grad. Ctr. Stu. & Res.
Principal Investigator:	Unknown
Project Description:	

Title:	Survey of Relative Burdens of Atmospherically Borne Metals in Britain
Contract No.:	
Supporting Organization:	United Kingdom Government
Performing Organization:	University of Wales
Principal Investigator:	Unknown
Project Description:	

Table 145 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - TRACE ELEMENTS

Title:	Correlation of Hazardous Compounds in Coal, Coal Ash, Fly Ash, and Other Emissions from Combustion
Contract No.:	
Supporting Organization:	U.S. Department of the Interior
Performing Organization:	U.S. Department of the Interior
Principal Investigator:	R. A. Friedel, A. G. Sharkey, R. G. Lett, and J. L. Shultz
Project Description:	
Title:	Removal of Trace Elements from Combustion Products
Contract No.:	
Supporting Organization:	U.S. Department of the Interior
Performing Organization:	U.S. Department of the Interior
Principal Investigator:	D. Bienstock, J. J. Demeter and C. R. McCann
Project Description:	
Title:	Potential Radioactive Pollutants Resulting From the Expanded Energy Programs: Quality Assurance Aspects
Contract No.:	RFP C1 75 0261
Supporting Organization:	U.S. EPA
Performing Organization:	
Principal Investigator:	
Project Description:	

Table 145 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS EMISSIONS - TRACE ELEMENTS

Title:	Trace Elements in Coal
Contract No.:	
Supporting Organization:	Ohio State Government
Performing Organization:	State Department of Natural Resources
Principal Investigator:	N. F. Knapp
Project Description:	

Title:	Evaluation of Pollution from Trace Elements in Coal
Contract No.:	
Supporting Organization:	U.S. Department of the Interior
Performing Organization:	U.S. Department of the Interior
Principal Investigator:	A. W. Deurbrouck
Project Description:	

Title:	Analytical Support to Include Comprehensive Analysis of Hazardous Substances in Residual Oil
Contract No.:	RFP DU-75-4321
Supporting Organization:	U.S. EPA
Performing Organization:	
Principal Investigator:	
Project Description:	

ASH HANDLING

Coal combustion accounts for about 99 percent of all ash generated by stationary combustion sources; almost all a product of electric utility and industrial combustion. Only a small percentage (~15 percent) of this ash is utilized and the remainder constitutes the predominant source of solid waste attributable to combustion processes. Although ash handling procedures are moderately well defined for utilities, industrial practices remain obscure and the present data base is poor. There are a substantial number of studies underway dealing with fly ash and bottom ash, primarily in the area of ash utilization. Other studies, such as those concerned with trace emissions, indirectly address the ash problems by providing information concerning control device efficiency, fly ash and bottom ash distribution, and chemical composition of ash fractions as a function of fuel used, control device, and boiler type.

Work in the areas of ash pond effluents, leachates and fugitive emissions from ash transport and storage is limited. EPA and other government agencies, such as the Army Corps of Engineers, Department of Interior, TVA, etc., do have a number of on-going or planned activities dealing with leachates, fixation processes, use and durability of pond liners, etc. Many are studies dealing with predictive models and laboratory measurement of migration rates and concentration of metals and anions, effect of heavy metals on various types of soil receptors, and interactions of metals and organics. Most of these studies are laboratory programs and the results need to be correlated with field tests.

A listing of some individuals presently involved in these areas of activity, their affiliations, and a brief description of their current activities follows:

- Leachates

  Dan Kranczk, EPA Corvallis - Chemical composition of leachates based on equilibrium concentrations which predict the concentration of metals and anions as free ions, bound species, and precipitated solids.

  Walt Sanders, Southeast Water Lab., Athens, Georgia - Similar to above study involving kinetics.

  Mike Roulier, EPA, Cincinnati and George Pinder, Princeton University - Migration rates of leachates. Model development based on soil column experiments.

  D. Whittemore, Kansas State University - Program sponsored by Department of Interior to study effect of combustion and landfill operations on water quality.

- Fixations and Liners

  Carlton Wiles, EPA, Cincinnati; Bob Landreth, EPA, Cincinnati; Rich Tabakin, Edison Laboratory; Dr. Richard Gullich, Richmond Field Station, Berkeley, California; TRW, Redondo Beach, California; and Metrecon, Oakland, California.

Table 146 lists projects dealing with the problems of ash handling and utilization.

Table 146. ON-GOING AND PLANNED ACTIVITIES: ASH HANDLING

Title:	Characterization of Effluents from Coal-Fired Power Plants
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Unknown
Principal Investigator:	Unknown
Project Description:	This is a project consisting of six different tasks. Three of those tasks are related to the FGD waste disposal program: (1) Assessment of pH Adjustment on Ash Pond Effluent, (2) Design of an Effective Monitoring Program for Ash Pond Effluent, and (3) Assessment of the Effect of Ash Leachate on Ground Water. The monitoring program design is expected to be completed in late 1975. The pH adjustment study should be completed by late 1976. The ash leachate/ground water study will be related to the EPA work with the U.S. Army (Dugway); the in-situ ash pond leachate and ground water characterization study should be complete by early 1977.
Title:	Geochemical Controls on Trace Element Concentrations in Natural Waters of a Proposed Coal Ash Landfill Site.
Contract No.:	
Supporting Organization:	U.S. Department of the Interior; Office of Water Research and Technology
Performing Organization:	Kansas State University
Principal Investigator:	D. O. Whittemore
Project Description:	Trace element concentrations will be determined in surface and ground waters in the drainage basins of a proposed landfill site. Models of the hydrologic cycle will be prepared.

Table 146 (continued). ON-GOING AND PLANNED ACTIVITIES: ASH HANDLING

Title:	Particle Characterization and Utilization of Fly Ash Resources in Illinois
Contract No.:	
Supporting Organization:	State of Illinois
Performing Organization:	State Geological Survey
Principal Investigator:	R. D. Harvey
Project Description:	The variable character of fly ash produced in coal-fired power plant is being examined to determine potential uses.
Title:	Chemical and Physical Examination of Ash, Slag and Fireside Reports from Lignite and Other Western Coals
Contract No.:	
Supporting Organization:	Bureau of Mines, Grand Forks, N. D.
Performing Organization:	Bureau of Mines
Principal Investigator:	W. W. Fowkes
Project Description:	A study to obtain fundamental data concerning the properties and composition of coal ash which influence deposition for a broad spectrum of western coals.
Title:	Western Coal Ash
Contract No.:	
Supporting Organization:	Bureau of Mines, Washington, D.C.
Performing Organization:	Bureau of Mines
Principal Investigator:	Unknown
Project Description:	Research to develop fundamental data on the composition and properties of western coal ash and to define mechanisms for removal of objectionable materials.

Table 146 (continued). ON-GOING AND PLANNED ACTIVITIES: ASH HANDLING

Title:	Improve the Thermal Efficiency and Availability of Boilers Burning Western Coals and Lignite
Contract No.:	
Supporting Organization:	Bureau of Mines, Grand Forks, N.D.
Performing Organization:	Bureau of Mines
Principal Investigator:	E. A. Sondreal
Project Description:	A commercial pulverized coal-fired boiler is being used to study fireside ash deposition. Chemical analyses of coal and ash are being conducted to establish the mechanism of fouling.
Title:	In Vitro Toxicity Studies on Fly Ash Extracts
Contract No.:	RP 483
Supporting Organization:	EPRI
Performing Organization:	Battelle Columbus Laboratories
Principal Investigator:	Unknown
Project Description:	The objective of this 1-year project is to determine the toxicity of extractable fractions from fly ash samples from both the combustion of coal and residual fuel oil. In addition, possible synergistic effects of NO_x and SO_x and polycyclic organic materials (POM) applied in conjunction with the fly ash extracts will be investigated.
Title:	Pilot Model Study - Ash Pond Water Recirculation
Contract No.:	
Supporting Organization:	TVA
Performing Organization:	TVA
Principal Investigator:	W. S. Wilburn
Project Description:	A model study will be made at Shawnee to determine problems anticipated in recirculating high pH ash pond water prior to installation of a full scale system.

Table 143 (continued). ON-GOING AND PLANNED ACTIVITIES: ASH HANDLING

Title:	Studies of Methods to Prevent Saturation of Closed-Loop Ash Pond Systems
Contract No.:	
Supporting Organization:	TVA
Performing Organization:	TVA
Principal Investigator:	B. G. McKinney
Project Description:	A study of method to desaturate closed-loop ash pond systems to prevent scaling.
Title:	Effects of Coal By-Products in Soil
Contract No.:	RP 202
Supporting Organization:	EPRI
Performing Organization:	Radian Corporation
Principal Investigator:	Unknown
Project Description:	The purpose of this research is to determine the amounts of toxic elements in scrubber sludge and fly ash and their leachability in various types of soil.
Title:	Fly Ash Characterization and Disposal
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	TVA
Principal Investigator:	Unknown
Project Description:	This is an expansion of a continuing project at TVA to characterize coal, ash, and ash effluents. Data will be compiled and summarized, emphasizing the quantity and physical/chemical characteristics. An extensive effort will be conducted for complete characterization of physical properties and chemical constituents of coal, ash, and ash effluent. A study of ash sluice water treatment methods, which would allow recycle/re-use, will be made. Promising methods for disposal and utilization of flyash will be identified based on results of the efforts just described.

COOLING SYSTEMS

Current research into cooling systems for conventional combustion installations is quite diversified. The principal organizations doing investigations include the Electric Power Research Institute (EPRI), the Energy Research and Development Administration (ERDA), the Environmental Protection Agency (EPA), the Battelle Memorial Institute, and various colleges and universities. The major emphasis of current projects centers upon the reduction of water consumption, the elimination of salt drift, and the reduction of thermal pollution and chemical contamination in water.

Battelle Memorial Institute is currently involved in studies on dry cooling methods. The investigations cover a variety of aspects of dry cooling, including an assessment of the state-of-the-art, optimum design of heat exchangers, and proposed advanced concepts. Battelle is currently operating a dry cooling test facility at the 30 MW Neil Simpson power plant in Wyodak, Wyoming, owned by the Black Hills Power and Light Company.

The Environmental Protection Agency is sponsoring a number of studies on dry and wet/dry cooling methods. The emphasis of the investigations is on optimization of design and operating characteristics from the viewpoint of economics, efficiency, and reduction of environmental impact. The programs are mainly demonstration projects which attempt to augment and verify existing information on dry and wet/dry cooling towers in order to optimize tower operation.

Salt drift or fallout from cooling tower plumes is a significant problem in the localized area of the tower. This has been a much investigated problem in the recent past. Further work is presently being done at the Turkey Point Plant in Florida where a mechanical draft wet tower is used for cooling condenser water. This report will be available in the near future. In order to prevent drift and associated land and vegetation damage, various organizations are looking into the improvement of mechanical drift eliminators, and the use of dry cooling towers.

A great deal of investigation and modeling of thermal water pollution is currently being done. Researchers at the Massachusetts Institute of Technology are very active in the field. The major emphasis of current studies concerns flow modeling, heat dissipation, and induced currents. There is also interest in determining near and far field heat distribution associated with various cooling water discharge schemes. The objective is to prevent the use of heated ambient water. In respect to this problem, MIT will be developing near and far-field thermal diffusion models at the Pilgrim Power Station in Plymouth, Massachusetts. In addition, studies will be carried out to develop circulation models in Boston Harbor. Table 147 lists on-going activities in the cooling system area.

Table 147. ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Cooperative Salt Water Cooling Tower Environmental Effects Study
Contract No.:	
Supporting Organization:	U.S. Nuclear Regulatory Commission
Performing Organization:	Maryland State Government
Principal Investigator:	Unknown
Project Description:	Cooperative study of the measurement of salt drift and resulting salt deposition from the operation of a large natural draft salt water cooling tower.
Title:	Chalk Point Cooling Tower Drift Study
Contract No.:	
Supporting Organization:	U.S. Nuclear Regulatory Commission
Performing Organization:	Environmental Systems Corporation
Principal Investigator:	F. M. Shofner
Project Description:	The study provides a demonstration of the drift performance of large natural draft cooling towers fitted with improved drift eliminators. Favorable drift performance, along with evidence that expected drift levels will not have unacceptable environmental impacts, will enhance the acceptability of such salt water cooling towers systems for use in future power plants, and will facilitate the siting of power plants in areas where water supplies have high salt content. The study will consist of: a. Direct measurements of drift rates at the large hyperbolic natural draft salt water cooling tower at the Chalk Point Power Station (Unit #4). b. Supporting measurements in the tower and power plant needed for analyses and interpretation of the drift measurement data. c. Acquisition of data from a nearby meteorological tower and atmospheric soundings, as required for the analyses of general plume behavior and predictions of salt deposition. d. Detailed meteorological measurements of the cooling tower plume itself to thoroughly characterize plume rise. e. Analyses of data obtained during the course of the field measurement study.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Salt Water Cooling Tower Study
Contract No.:	
Supporting Organization:	Jersey Central Power & Light Company
Performing Organization:	Jersey Central Power & Light Company
Principal Investigator:	J. F. McConnell
Project Description:	Investigation of engineering and environmental feasibility of salt water cooling towers for Forked River Unit #1. Measurement of drift from existing fresh water towers in order to predict drift from salt water towers and apply results to determine environmental effects. Investigation of blowdown and chemical treatment effects and establishment of general engineering reference design.

Title:	Cooling Tower Salt Drift, Post Operation Monitoring Program
Contract No.:	
Supporting Organization:	Atlantic City Electric Company
Performing Organization:	Atlantic City Electric Company
Principal Investigator:	R. J. Waukner J. Kovago
Project Description:	Atlantic City Electric Company completed erection of the first sea water cooling tower in the country in December 1974. Ambient salt concentration and deposition caused by natural conditions has been extensively monitored for 1 year pre-op in order to establish firm background information. This salt monitoring will be continued in the first year of tower operation and its results will be compared to the natural salt deposition data. It is expected that this study will reveal the true environmental impact, if any, of a neutral draft, sea water cooling tower.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Research Initiation - Improvement of Evaporative Cooling Tower Performance
Contract No.:	
Supporting Organization:	U.S. National Science Foundation Division of Engineering
Performing Organization:	Drexel University School of Engineering
Principal Investigator:	C. W. Savery, Thermal & Fluid Sciences
Project Description:	The objective of the program is to study the processes occurring in evaporative cooling towers. The first phase of this research has been devoted to analytical and experimental study of packing performance. Current research concentrates on the problem of cooling tower drift, with emphasis on methods of reduction of drift particles containing dissolved salts which are emitted by cooling towers circulating salt water. The research will include modeling of drift entrainment, transport and deposition. Experiments will involve the use of drift eliminator devices in conjunction with a model cooling tower.
Title:	Effects of Cooling Tower Blowdown
Contract No.:	
Supporting Organization:	Wisconsin State Government
Performing Organization:	University of Wisconsin School of Engineering
Principal Investigator:	G. F. Lee
Project Description:	The primary objective of the project is to determine the characteristics of blowdown from cooling towers. The project is motivated by questions of whether the utilization of once-through cooling and the associated heating of the waters in the region of the discharge has a greater environmental impact than the discharge of blowdown from cooling towers used for waste heat dissipation. The study consists of monitoring cooling tower blowdown from a wide variety of cooling towers located in the upper Midwest.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Cooling Tower and Cooling Pond Atmospheric Impact
Contract No.:	
Supporting Organization:	U.S. Nuclear Regulatory Commission
Performing Organization:	Battelle Memorial Institute
Principal Investigator:	M. A. Wolf
Project Description:	Efforts range from a comprehensive state-of-the-art review of pertinent research to consideration of potential methods for modifying recognized consequences. Emphasis, however, is placed on field studies for the acquisition of an adequate data base to provide an understanding of the interaction with the atmosphere of cooling towers and cooling ponds. Current models for the prediction of plume rise and dispersion, cloud formation, fogging, and icing are evaluated with these data and adapted as necessary. Additional models are developed where appropriate. The field portion focuses attention on the plume dynamics and on the microphysical and chemistry properties of the plumes. Thus, a variety of measurement techniques are utilized in the definition of plume characteristics on the meso- and microscales.
Title:	A Study of the Plume From a Brackish Water Natural Draft Cooling Tower and Its Effects On the Environment
Contract No.:	
Supporting Organization:	U.S. Nuclear Regulatory Commission
Performing Organization:	University of Maryland Water Resources Research Center
Principal Investigator:	J. Pell
Project Description:	The object of this study is to completely characterize the effluent plume discharged into the atmosphere from a natural draft, evaporative, cooling tower employing brackish water and to determine the plume's effect on the vicinity's meteorology, air quality, vegetation, and soils. Measurements will be made from the top of the tower where the

	plume enters the atmosphere, rather than just above the fill. Laser light scattering will be used for the measurement of droplet size distribution of the saline drift. This data will be complemented by isokinetic and sensitive paper sampling. Measurements will also be made of the vertical updraft velocity, and plume temperature and water vapor content. Metric quality photographs of the plume will also be taken. A microwave tower, in the vicinity of the plant, will be equipped with instrumentation to measure local meteorological data. Vegetation and soil samples will be taken before and after the cooling tower start up to determine the effects of the plume.
Title:	Thermal Studies - Atlantic Generating Station
Contract No.:	
Supporting Organization:	Public Service Electric and Gas Company, New Jersey
Performing Organization:	Massachusetts Institute of Technology
Principal Investigator:	Prof. D. R. F. Harleman Prof. K. D. Stolzenbach
Project Description:	Experimental studies will determine the interaction of the ocean bottom with heated surface and subsurface discharges. The objective is to develop analytical or numerical techniques for predicting near and far-field temperature distribution in coastal waters. Results of measurements of ocean currents and temperature distribution and dye diffusion observations at the proposed site have been incorporated into a mathematical model of the far-field temperature distribution. Statistical characterization of receiving water states are being developed in conjunction with the application of this model. The project is scheduled for completion December 1975.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Dynamic of Shallow Cooling Ponds
Contract No.:	
Supporting Organization:	Stone & Webster Eng. Corp. and Virginia Electric Power Company
Performing Organization:	Massachusetts Institute of Technology
Principal Investigator:	Prof. D. R. F. Harleman Prof. J. J. Connor Dr. G. H. Jirka
Project Description:	(1) Basic study of the buoyance driven vertical circulation of cooling water into long shallow side arms of cooling ponds. (2) Development of a transient cooling pond model for heat distribution in shallow cooling ponds with lateral and vertical restrictions. This includes the development of a two-layered finite element model for solution of the mass heat and momentum conservation equations. Specific application of this investigation is the North Anna Cooling Lake in Virginia.
Title:	Diffuser Induced Circulations in Shallow Coastal Zones
Contract No.:	
Supporting Organization:	Waste Heat Management Research Program of the MIT Energy Laboratory
Performing Organization:	Massachusetts Institute of Technology
Principal Investigator:	Dr. D. R. F. Harleman Dr. G. H. Jirka Dr. J. G. Steele
Project Description:	Submerged multiport diffusers for the disposal of waste heat from thermal-electric power generating facilities discharge a considerable amount of cooling water with substantial momentum. In shallow coastal waters these diffusers have the potential of inducing currents of considerable magnitude. An understanding of the induced current pattern is necessary to assess potential heat re-entrainment and the effect on coastal morphology. A theoretical investigation combined with a series of basic experiments is planned.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Design of Environmental Monitoring Programs
Contract No.:	
Supporting Organization:	MIT Energy Laboratory
Performing Organization:	Massachusetts Institute of Technology
Principal Investigator:	Prof. S. F. Moore
Project Description:	Development of quantitative methodologies for the design of hydrothermal and biological monitoring programs for waters subject to heated water discharges.
Title:	Physical, Chemical, and Biological Effects of Heat Added to Missouri River by Lignite-Fired Power Stations Near Stanton, North Dakota
Contract No.:	
Supporting Organization:	Basin Electric Power Corporation, Inc.
Performing Organization:	University of North Dakota
Principal Investigator:	J. K. Neel
Program Description:	
Title:	Power Plant Waste Heat Rejection System Using Dry Cooling Tower
Contract No.:	
Supporting Organization:	EPRI
Performing Organization:	Union Carbide, Linde Division
Principal Investigator:	Unknown
Project Description:	This 1-year project will establish the economic feasibility of a dry cooling concept that utilizes advanced heat transfer technology to achieve high heat transfer rates, incorporating enhanced heat transfer surfaces in conjunction with a phase change of the dense fluid transporting heat between the steam condenser and the cooling tower.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Cooling Water Discharge
Contract No.:	RP 49
Supporting Organization:	EPRI
Performing Organization:	Johns Hopkins University
Principal Investigator:	Unknown
Project Description:	Since 1962, the electric utility industry has sponsored studies at Johns Hopkins University on the effects of power plant cooling water discharge on rivers, lakes, and other bodies of water. Fish entrapment and the entrainment of organisms are also under investigation.
Title:	Agricultural Waste Water for Power Plant Cooling
Contract No.:	RP 373
Supporting Organization:	EPRI
Performing Organization:	California Department of Water Resources
Principal Investigator:	Unknown
Program Description:	This 2-year project will: (1) develop an economical and reliable pretreatment method for agricultural waste water to reduce its scale-forming tendencies; (2) develop methods for allowing a cooling tower to operate with a large concentration ratio; (3) further the concentration of cooling tower blowdown to a high total dissolved solids level; and (4) study regeneration of the reactants used in the pretreatment process.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Cherne Thermal Rotor Test Program
Contract No.:	RP 420
Supporting Organization:	EPRI
Performing Organization:	Cherne Industrial, Inc.
Principal Investigator:	Unknown
Project Description:	The 8-month test program will be carried out at a utility plant site and will involve a significantly large installation and requisite instrumentation to establish the interference effects, wind sensitivity, plume characteristics, and drift performance, as well as the heat dissipative capacity, of the Cherne Thermal Rotor System.
Title:	Thermal Discharge State-of-the-Art
Contract No.:	RP 283
Supporting Organization:	EPRI
Performing Organization:	Environmental Analysts, Inc.
Principal Investigator:	Unknown
Project Description:	Environmental Analysts, Inc., is studying the current state of technology on waste heat management in electric power plants. It will include: (1) blowdown disposal; (2) waste water utilization; (3) strategies in obtaining low- or zero-discharge cooling systems; (4) thermal discharge simulation; (5) field monitoring; and (6) dry cooling systems.
Title:	Performance, Economics, and Reliability of Cooling Tower-Cooling Pond Mix
Contract No.:	RP 321
Supporting Organization:	EPRI
Performing Organization:	Auburn University
Principal Investigator:	Unknown
Project Description:	This 1-year study will evaluate the performance and cost of employing a cooling tower-cooling pond mix and compare the results by using towers and ponds separately. The study

	will also determine the geographic regions of the U.S. where the mixed-cooling concept might be employed.
Title:	Forecasting Power Plant Effects on the Coastal Zone
Contract No.:	RP 575
Supporting Organization:	ERPI
Performing Organization:	EG&G, Environmental Consultants
Principal Investigator:	Unknown
Project Description:	The objective of this on-going project is to advance understanding of far-field dispersion of emissions from power plants on an open coast as affected by physical oceanographic processes. Air and sea temperatures and current, wind, and tide data have been taken for an area offshore the Pilgrim Power Station near Plymouth, Mass. The study will provide for verification of mathematical models of the coastal dispersion sites.
Title:	Cooling Tower/Stack Gas Plume Interaction
Contract No.:	EHB 540 77ADA, Task 1
Supporting Organization:	EPA, EPRI, State of Maryland
Performing Organization:	Unknown
Principal Investigator:	Unknown
Project Description:	The purpose of this airborne monitoring project is to: (a) Characterize the heat and water vapor plume emitted from a natural draft cooling tower. (b) Evaluate the interaction between the cooling tower plume and three adjacent fossil fuel power plant stack plumes to determine formation and fate of acid droplets. (c) Evaluate aircraft safety relevant to turbulence, icing potential, and visibility impairment produced by the plume. The study will be done at Potomac Electric Power Company's Chalk Point Power Plant and will run from June 1975 to June 1976.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Optimizing Wet/Dry Cooling Towers for Water Conservation and Plume Abatement
Contract No.:	EHB 531 77AAY, Task 3
Supporting Organization:	U.S. EPA
Performing Organization:	United Engineers, Inc.
Principal Investigator:	Unknown
Project Description:	Assessment of the technical and economic feasibility of minimizing water use and reducing vapor plume discharges from wet/dry cooling towers. Analyses will be conducted at five sites in the western U.S. and will include consideration of meteorology, water quantity, and water quality. The project will be active from June 1975 to June 1976.
Title:	Demonstration of a Wet/Dry Cooling Tower
Contract No.:	EHB 531 77BBE, Task 3
Supporting Organization:	U.S. EPA
Performing Organization:	TVA
Principal Investigator:	Unknown
Project Description:	The project will provide technical and economic data on wet/dry cooling tower performance with regard to wet/dry heat transfer mechanisms, plume abatement, water conservation, and energy requirements. An extensively instrumented wet/dry tower of highly variable operating capability will be used. The project is intended to yield data to augment and verify analytical data presently available. The project began in May 1975 and is scheduled for completion in June 1977.

Table 147 (continued). ON-GOING AND PLANNED ACTIVITIES: COOLING

Title:	Optimizing Design Specifications for Large Dry Cooling Systems
Contract No.:	1 BB 392 21 AZU, Task 33
Supporting Organization:	U.S. EPA
Performing Organization:	PFR Engineering Systems, Inc., Marina Del Rey, Ca.
Principal Investigator:	Unknown
Project Description:	The project is intended to develop a rigorous and optimal procedure for evaluating dry cooling tower performance and economics. Mechanical draft dry cooling towers and direct contact jet condensers will be studied. Variables considered will include tower height, water flow rate, module design on bus-bar cost, and others. The project began June 10, 1975 and is scheduled for completion August 10, 1976.
Title:	Dry Cooling Tower Demonstration and Performance Study
Contract No.	EHB 531, 77AAY, Task 2
Supporting Organization:	U.S. EPA
Performing Organization:	Town of Braintree, Massachusetts
Principal Investigator:	Unknown
Project Description:	The project will demonstrate the use of a dry cooling tower on a combined cycle (gas turbine/steam cycle) power plant in order to evaluate operating performance and environmental consequences of the plant. The study will assess steam flow and distribution and temperature to help define optimal design characteristics. The project will also investigate meteorological effects, noise generation, and air quality in order to determine the economic impact of design and operational factors. The project began in June 1975 and is scheduled for completion sometime in 1979.

BOILER WATER TREATMENT AND OPERATION

Modern boilers operate at high steam pressures and, therefore, are susceptible to a variety of hazards associated with the use of unacceptably contaminated feed water. The major problem areas are scale deposition and corrosion in the boiler system and solid particle erosion and cracking of turbine components.

A new trend in specifying proper boiler water condition is the emphasis on minimizing caustic alkalinity. At low operating pressure, alkalinity will produce carryover problems at concentrations which do not promote corrosion in the boiler system. As pressure increases, corrosion becomes very highly dependent upon alkalinity and very strict limitations must be made. In conjunction with this, investigations are being made into current boiler operation standards in order to establish the state-of-the-art and recommend operating standards which should be altered.

The ASME Research Committee on Water in Thermal Power Systems is currently determining the important areas of research required in order to prevent or minimize turbine damage. Selection of appropriate investigations is a difficult effort because turbine problems are generated by a wide variety of factors. It is possible that investigations will center upon the dynamic behavior of contaminants saturated in the steam as they pass through the turbine.

Battelle Memorial Institute in Columbus, Ohio, is investigating boiler feed water chemistry with regard to control of corrosion and scale deposition. They are considering various volatile and nonvolatile agents and will make recommendations on allowable concentrations.

The Electric Power Research Institute is currently sponsoring studies which are applicable to conventional boiler system feed water treatment and control. Combustion Engineering is under contract to investigate volatile chemistry treatment in nuclear steam generation systems. The results should be applicable to conventional fossil fuel boilers in that corrosion of steam generator tubing will be simulated in a number of ways. The study will simulate condenser leakage and the affects of changeover from phosphate treatment to volatile chemistry (hydrazine and morpholine) treatment. Combustion Engineering is also looking into new methods of boiler water tube acid cleaning and improvements in cleaning with inhibited hydrochloric acid. The investigations include analysis of affects on boiler materials by testing of failure samples.

Babcock and Wilcox is active in updating a manual on methods of high purity boiler water analysis. High purity refers to detection of contaminants present in concentrations of parts per billion.

Much of the work being done regarding boiler feed water treatment and specifications is proprietary information. Only a minor number of projects were specifically identified and are not considered to be representative of the major thrust of research. However, some projects related to corrosion and power plant waste water disposal are listed in Table 148.

Table 148. ON-GOING AND PLANNED ACTIVITIES: BOILER WATER TREATMENT AND OPERATION

Title:	Structural Design Concepts for Increased Reliability and Safety in Power Plant Condensing Systems
Contract No.:	RP 372
Supporting Organization:	EPRI
Performing Organization:	University of Pennsylvania
Principal Investigator:	Unknown
Project Description:	The objective of this 2-year program is to reevaluate traditional condenser structural design methods by: (1) establishing rational design criteria for tube support plates; (2) establishing design rules relating to deformation of condenser flat-plate sections stayed by discrete pipes; and (3) performing theoretical analyses and scale-model tests to determine the stress distributions in built-up pressure vessels such as condenser meter boxes.
Title:	Preparation of Data Record on High Temperature Oxidation and Corrosion of Metals and Alloys in Electrical Generating systems
Contract No.:	RP 538
Supporting Organization:	EPRI
Performing Organization:	University of Liverpool, England Battelle Columbus Laboratories
Principal Investigator:	Unknown
Project Description:	This is an 18-month project. Experience relating to the high temperature oxidation and corrosion of metals and alloys in circumstances relevant to fossil-fuel-fired systems is very extensive and is dispersed over a wide range of scientific and technical literature, governmental, and other reports, and unpublished experience within companies and utilities. Collection of this into one record would greatly aid the designers and operators of fossil-fuel-fired systems in avoiding potentially corrosive situations.

Table 148 (continued). ON-GOING AND PLANNED ACTIVITIES: BOILER WATER TREATMENT AND OPERATION

Title:	Overall Power Plant Water Recycle/Reuse Studies - Pacific Northwest Environmental Research Laboratory
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Radian Corporation
Principal Investigator:	Unknown
Project Description:	This is a contract with Radian Corporation to determine over-all power plant water management systems to minimize water use. Recycle and treatment/reuse process simulations, using actual power plant field data as input, and preliminary system design and economic studies will be made on four different power plants representing four different areas of the United States. This effort, which is expected to be completed by mid-1976, will be coordinated with the TVA Fly Ash Characterization and Power Plant Effluent Studies. Pilot plant testing based on results of this study is expected to commence in early 1977.

FUELS AND FUEL STORAGE AND HANDLING

The anticipated growth in the use of coal has spurred greater interest in fuel conversion and coal properties including chemical content, volatility, ash fusibility, agglomerating tendencies, heat content, coal size and grindability. All of the above chemical and physical properties of coal influence furnace and firing equipment design and maintenance and have an important bearing on emissions and the use and performance of control equipment.

Coal handling practices will vary greatly depending upon the size of the combustion units, the type of combustion unit, land and storage area availability, etc. EPRI, the National Coal Association, and all users of fuels have an interest in fuel storage and handling practices. However, there is no typical plant and information on emissions from coal storage and handling is practically nonexistent in the literature. The only known studies now underway or planned which deal with coal storage and handling emissions are the Monsanto Research Corporation's stationary source assessment studies which have dealt with air emissions and a planned TVA study dealing with coal pile drainage slated for completion in 1976.

One area that has not been covered in any detail in this report concerns the reduction of sulfur prior to combustion by physical cleaning methods. EPA has been conducting research for a number of years, with the Bureau of Mines to improve coal washing processes. EPA has also funded a characterization of the washability of Northern Appalachian coal. This approach has been found to reduce the average pyritic sulfur content from 2.05 percent to 0.75 percent at a coal recovery yield of 90 percent. Regardless of yield the average organic sulfur content of the coals studied was 1.2 percent. A recent summary of coal washability studies is presented in an EPA report by L. Hoffman, et al., entitled "An Interpretive Compilation of EPA Studies Related to Coal Quality and Cleanability." A list of programs relating to fuels and fuel handling is given in Table 149.

Table 149. ON-GOING AND PLANNED ACTIVITIES: FUELS AND FUEL HANDLING

Title:	Characteristics of Coal Slurries
Contract No.:	RP 314
Supporting Organization:	EPRI
Performing Organization:	Stanford University
Principal Investigator:	Unknown
Project Description:	The objective of this 3-year project is to develop improved design criteria for the flow of and heat transfer from coal slurry mixtures. Viscometric coefficients and heat transfer characteristics of slurries will also be measured.
Title:	Organic Sulfur Constituents in Coal
Contract No.:	RP 267
Supporting Organization:	EPRI
Performing Organization:	University of Florida
Principal Investigator:	Unknown
Project Description:	This 3-year program will isolate the organic sulfur in coal by chemical means and identify the nature of the isolated organic sulfur compounds.
Title:	Reduction of Inorganic Sulfur in Dry Pulverized Coal Using High Intensity Magnetic Separation.
Contract No.:	RP 540
Supporting Organization:	EPRI
Performing Organization:	Indiana University Foundation
Principal Investigator:	Unknown
Project Description:	The objective of this 1-year project is to determine the relationship between magnetic separation process variables and the extent of pyritic sulfur reduction so that a meaningful economic evaluation can be prepared. Many highly pyritic Appalachian coals will not meet environmental restrictions on

Table 149 (continued). ON-GOING AND PLANNED ACTIVITIES: FUELS AND FUEL HANDLING

	allowable sulfur content. The sulfur content of such coals may be reduced to acceptable levels by utilization of high intensity magnetic separation to remove weak magnetic pyritic sulfur compounds from a coal-air mixture.
Title:	Technology Assessment of Preparation of Coal for Combustion and Conversion
Contract No.:	RP 466
Supporting Organization:	EPRI
Performing Organization:	Unknown
Principal Investigator:	Unknown
Project Description:	The objective of this 1-year project is to provide a comprehensive, authoritative, and responsible description of coal preparation technologies. Coal preparation refers to those techniques and processes used to improve the quality of coal prior to its use (removal of sulfur-bearing minerals, separation of rocks, etc.) Also included are those methods used to control the heating value of coals through blending and stockpile maintenance.
Title:	Review of Coal Cost and Production Studies
Contract No.:	RP 335
Supporting Organization:	EPRI
Performing Organization:	Pennsylvania State University
Principal Investigator:	Unknown
Project Description:	This 1-year project will review recent and ongoing studies to ascertain the state of knowledge of coal supply. Projections of cost and output, and the methods by which the projections are made, will be critically analyzed.

Table 149 (continued). ON-GOING AND PLANNED ACTIVITIES: FUELS AND FUEL HANDLING

Title:	Review of Natural Gas Supply Studies
Contract No.:	RP 436
Supporting Organization:	EPRI
Performing Organization:	Mathematica, Inc.
Principal Investigator:	Unknown
Project Description:	A critical review and assessment and a comparative analysis of 12 gas supply studies, including the Federal Energy Administration and the National Petroleum Council studies, will be performed in this 4-month project.
Title:	Assessment of Capability of the Existing Transportation Network for the Movement of Increased Amounts of Coal
Contract No.:	RP 437
Supporting Organization:	EPRI
Performing Organization:	Mathematica, Inc.
Principal Investigator:	Unknown
Project Description:	The purpose of this 6-month study is to develop a system of measures of aggregative interregional transportation capacity and to identify any of the links where transportation bottlenecks might occur.
Title:	Fuel Utilization in Residential Heating
Contract No.:	RP 137
Supporting Organization:	EPRI
Performing Organization:	Ohio State University
Principal Investigator:	Unknown
Project Description:	Investigation of a procedure for calculating accurately the energy requirements of single and multiple residential housing units. It is intended that the procedure be applicable to both electric and fossil fuel heating systems in order to determine precisely the difference in the amounts of fuel raw energy required to heat houses of similar structure.

Table 149 (continued). ON-GOING AND PLANNED ACTIVITIES: FUELS AND FUEL HANDLING

Title:	Development of Models to Aid in Forecasting Residential Energy Usage
Contract No.:	RP 931
Supporting Organization:	EPRI
Performing Organization:	Data Resources, Inc.
Principal Investigator:	Unknown
Project Description:	The purposes of this 1-year study are to develop improved data bases and forecasting methodology for energy use in the residential sector and to develop a data file on residential usage of electricity, natural gas, and fuel oil, by state, for 1950 to 1973.
Title:	Forecasting the Industrial Demand for Energy
Contract No.:	RP 433
Supporting Organization:	EPRI
Performing Organization:	Econometrica International
Principal Investigator:	Unknown
Project Description:	This 1-year project will have three phases: (1) survey of existing work on industrial energy demand, development of analytic approaches, and review of data sources; (2) analysis and empirical research into two industries; and (3) application of knowledge gained in (2) to the full list of industries.
Title:	Assessment of Energy Modeling (2 parts)
Contract No.:	RP 333
Supporting Organization:	EPRI
Performing Organization:	Charles River Associates, Inc.
Principal Investigator:	Unknown

Table 149 (continued). ON-GOING AND PLANNED ACTIVITIES: FUELS AND FUEL HANDLING

Project Description:	Part I:	An assessment of the state-of-the-art in electric power demand forecasting techniques, with special emphasis on forecasting reliability.
	Part II:	An assessment of energy systems models that integrate supply, demand, environmental, and other considerations, with emphasis on electric power problems.

FLUE GAS DESULFURIZATION

Present research into methods of SO_x removal from combustion stack gases is extremely diversified. Potential removal processes range from fuel pretreatment for sulfur reduction to collection of SO_x as it exits the stack. The EPA is sponsoring a great number of projects on flue gas cleaning waste disposal. They and other projects are listed in Table 150.

Table 150. ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Prototype Study of Limestone Scrubbing for SO_2 - Dust Removal Systems
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Bechtel Corporation
Principal Investigator:	I.A. Raben
Project Description:	The objectives of this contract are: to complete the detailed design of a highly versatile, prototype limestone wet scrubbing facility; to procure major equipment; to design and conduct a 2-year test program to evaluate limestone wet scrubbing processes; and to analyze, evaluate, and report the test results. A comprehensive process and mechanical design report will be issued. The test program is now being conducted at TVA's Shawnee Steam Plant, near Paducah, Kentucky.
Title:	Development of Active Carbon SO_x Sorption and Sulfur Recovery Process
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Westvaco
Principal Investigator:	F. J. Ball
Project Description:	The purpose of this effort is to determine technical feasibility of the power plant flue gas desulfurizing and elemental sulfur recovery process using activated carbon as SO_x sorbent. The process essentially consists of sulfur oxides sorption, sulfuric acid decomposition and active carbon regeneration stages. The reactive gas, hydrogen sulfide, needed for sulfuric acid decomposition, is generated internally in the active carbon regeneration stage. Elemental sulfur is the byproduct of this process. Pilot plant investigations, now in progress, are aimed to determine sets of principal operating parameters

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

	for all process stages which then will be integrated and run continuously for some time in a cyclic manner.
Title:	Wet Scrubber Study
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	West Virginia University
Principal Investigator:	Dr. D. Y. Wen
Project Description:	The objective of this study is: 1) To clearly define the reaction mechanism of SO_2 absorption by various solutions, such as CaO-, $CaCO_3$-, CaOH-, Na_2CO_3- solutions. 2) Elucidate the phenomena taking place in various types of wet scrubbers such as venturi, packed tower, spray tower, and turbulent bed contractor, both from the mechanical and absorption-kinetic points of view. 3) Find optimal operating conditions and provide the design and scale-up criteria of wet scrubber process which will result in the most efficient and economic absorption performance. To achieve objectives, mathematical models describing the phenomena in these scrubber processes will be devised.
Title:	Development of the Stone & Webster Process for SO_2 Removal and Recovery
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Wisconsin Electric Power Company
Principal Investigator:	C. W. Fay
Project Description:	The EPA and Wisconsin Electric Power Company program is as follows: Phase I - Design, Installation and Operation of an integrated pilot plant; development of prototype scale electrolytic cell system; preliminary design of 75 Mw prototype system and development of detailed test programs and operating schedules.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

	Based on evaluation of results from Phase I and continued favorable assessment of technical and economic feasibility, the program will continue as follows: Phase II - Detailed design, procurement and installation of a 75 MW prototype system. Phase III - Start-up and operation of the 75 MW prototype system.
Title:	Shell Flue Gas Desulfurization Process Pilot Plant
Contract No.:	
Supporting Organization:	Tampa Electric Company
Performing Organization:	Tampa Electric Company
Principal Investigator:	J. Pohlenz, D. J. Rankin
Project Description:	Purpose is to test the system on a coal-fired boiler in an effort to determine technical feasibility and operating parameters of the modular reactor and its ability to remove SO_x from flue gas. Successful operation could lead to further development and/or application on a larger or full sized utility boiler.
Title:	Sulfur Dioxide Removal from Flue Gases
Contract No.:	
Supporting Organization:	Universal Oil Products Company
Performing Organization:	Universal Oil Products Company
Principal Investigator:	Dr. A. K. Sparks
Project Description:	The object of this work is the removal of sulfur dioxide from flue gases - principally from power generating stations that burn coal or residual oil. Two processes are currently under development - one uses a liquid absorption system, the other utilizes a regenerable solid adsorbent at high temperatures. Both processes yield elemental sulfur as the product.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES:
FLUE GAS DESULFURIZATION

Title:	Evaluation of Advanced Regenerable Flue Gas Desulfurization Processes
Contract No.:	RP535
Supporting Organization:	EPRI
Performing Organization:	Radian Corporation
Principal Investigator:	Unknown
Project Description:	The primary objective of this 6-month project is to provide the utility industry with a comparative state-of-the-art evaluation of developmental regenerable flue-gas desulfurization processes.
Title:	Pilot Test and Evaluation of Three Prototype Flue Gas Desulfurization Processes.
Contract No.:	RP536
Supporting Organization:	EPRI
Performing Organization:	Southern Services, Inc.
Principal Investigator:	Unknown
Project Description:	The Southern Company has installed 20 MWe pilot plants of three second-generation flue-gas desulfurization processes at the Scholtz Steam Plant of Gulf Power Co. The processes being evaluated during this 18-month period are: (1) the A. D. Little/Combustion Equipment Associates Double Alkali Process (Sodium/Calcium), (2) the Foster-Wheeler/Bergbau-Forschung Dry Coal Char Adsorption Process, and (3) the Chivoda Thorobred 101 Dilute Acid Adsorption Process. These prototype pilot plants have been designed to permit operation in a utility context over a wide variety of operating conditions, fuel types, and gas-flow rates.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Development of Improved Lime/Limestone Scrubbing Technology
Contract No.:	RP535
Supporting Organization:	EPRI
Performing Organization:	TVA
Principal Investigator:	Unknown
Project Description:	This 18-month project is directed to expanding an existing development and process evaluation program at the TVA Colbert Lime/Limestone scrubbing pilot plant to include four additional high priority tasks required in achieving a commercial design base for lime/limestone scrubbing on high-sulfur coal.

Title:	SO_2 Removal from Stack Gases
Contract No.:	
Supporting Organization:	Foster Wheeler Corporation
Performing Organization:	Dairyland Power Cooperative
Principal Investigator:	Unknown
Project Description:	Injection of powdered dolomite into the hot flue area of the boiler system.

Title:	Wet Scrubber Pilot Plant Test
Contract No.:	
Supporting Organization:	Northern States Power Company
Performing Organization:	Northern States Power Company
Principal Investigator:	J. A. Noer
Project Description:	A temporary installation for testing and analysis of a 12,000 CFM wet scrubber on unit No. 1 at Black Dog Generating Plant, will duplicate in reduced scale, the Combustion Engineering wet scrubber now being designed for installation at the Sherburne County Generating Plant. The findings of this pilot installation will be used to verify the CE Design and assure its ultimate full scale operation by investigating SO_2 and particulate removal rates, scaling, water chemistry, ash hold-up pond chemistry, materials corrosion, etc.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Flue Gas Cleaning Waste Characterization and Disposal Evaluation
Contract No.:	
Supporting Organization:	U.S. EPA.
Performing Organization:	Aerospace Corporation
Principal Investigator:	Unknown
Project Description:	A broad-based study is being performed (1) to identify environmental problems associated with FGC waste disposal, (2) to assess current FGC waste disposal methods (both technically and economically), and (3) to make recommendations regarding alternate disposal approaches. The effort includes chemical and physical characterization of untreated and treated (fixed, oxidized, stabilized) FGC wastes, technical support of the FGC waste disposal demonstration at Shawnee, and coordinating all FGD waste related R&D activities (EPA, TVA, private industry) including publishing an annual integrated report.

Title:	Shawnee Field Evaluation of Flue Gas Cleaning Waste Disposal Methods
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Interagency Agreement with TVA and the Aerospace Corporation
Project Description:	The current program evaluates the Chemfix, Dravo, and IUCS processes for chemical fixation of scrubber wastes in three separate disposal ponds. Untreated lime and limestone wastes are placed in two additional ponds. Leachate, run-off and groundwater samples as well as core samples of the wastes and soil are being collected and analyzed to evaluate environmental effects. Both Aerospace Corporation and TVA are performing selected analyses; Aerospace is responsible for data evaluation and reporting. Future plans call for evaluation of other disposal approaches, including gypsum disposal.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Louisville Gas and Electric Lime Scrubbing Waste Disposal Laboratory and Field Evaluation
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Louisville Gas and Electric
Principal Investigator:	Unknown
Project Description:	This is part of a contract with Louisville Gas and Electric (LG&E) for lime and carbide lime scrubbing tests and waste disposal studies. Both physical stabilization (e.g., by adding fly ash) and chemical fixation will be evaluated in laboratory studies, subsequently followed by field evaluation of the lab results. The field evaluation will consist of "swimming pool" tests in which all leachate will be collected and disposal site tests (similar to Shawnee) in which soil-leachate interactions can be evaluated.
Title:	Laboratory and Field Evaluation of 1st and 2nd Generation Flue Gas Cleaning Waste Treatment Processes
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Interagency Agreement with U.S. Army Corps of Engineers
Principal Investigator:	Unknown
Project Description:	This program will evaluate fixation processes for several industrial wastes, including FGC wastes. Initial efforts in this project were similar to Aerospace laboratory studies of Chemfix, Dravo, and IUCS processes except that additional commercial processes are being evaluated. Independent studies of fixation, including some of the Corps' own ideas, are planned for the near future. In addition, field evaluation of current disposal practices and small-scale field tests of fixation are planned.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Evaluation of Alternate Flue Gas Cleaning Waste Disposal Sites
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Unknown
Principal Investigator:	Unknown
Project Description:	This project will technically and economically assess the potential for using abandoned mines, operating mines, and the ocean as FGC disposal sites. Small-scale field studies will be initiated for those alternatives showing promise.
Title:	Flue Gas Cleaning Waste Leachate/Soil Attenuation Studies
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Interagency Agreement with the U.S. Army Material Command
Principal Investigator:	Unknown
Project Description:	Experiments are being performed to determine the extent to which heavy metals and other chemicals from industrial wastes and FGC Wastes can migrate through (or, conversely, be attenuated by) soil in land disposal sites. Currently, 13 industrial wastes and 3 untreated FGC wastes are included in the program.
Title:	Flue Gas Cleaning Waste Leachate/Liner Compatibility Studies
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Interagency Agreement with the U.S. Army Corps of Engineers
Principal Investigator:	Unknown
Project Description:	This project will consist of physical testing of approximately 18 liner materials which have been exposed to 2 different FGC wastes

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

	for periods of 12 and 24 months. An economic study of material and construction/placement costs will also be performed.
Title:	Development of Flue Gas Cleaning Waste Disposal Standards
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Unknown
Principal Investigator:	Unknown
Project Description:	The project will consist of the establishment of criteria which can ultimately be used to determine the best alternatives for a given plant situation, the tentative selection (for study purposes) of water quality standards which could be applied to FGC waste disposal standards or guidelines, the study of the economic and other effects of applying the standards selected, and drafting a preliminary set of guidelines which can be used as a basis for ultimately formulating final guidelines and determining research and development needed to support their formulation. This effort is expected to take a minimum of 1 year.
Title:	Kellogg Flue Gas Cleaning Waste Conversion Pilot Studies
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	M. W. Kellogg
Principal Investigator:	Unknown
Project Description:	Performance of pilot studies of two process steps which are part of the Kellogg "Kel-S" process for converting sludge into $CaCO_3$ and elemental S. The process steps to be studied are (1) the continuous drying/reduction kiln conversion of FGC waste to CaS (using coal as the reductant) and (2) the dissolution of CaS and liberation of H_2S. This process appears to represent a viable alternative to FGC waste disposal.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Processing Lime/Limestone Wet Scrubbing Wastes for Disposal or Utilization
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	Unknown
Principal Investigator:	Unknown
Project Description:	This project consists of two tasks: (1) a study of fertilizer production using lime/limestone scrubbing wastes as a filler material and (2) a study to characterize lime/limestone scrubbing wastes physically and chemically as a function of the operating conditions under which they are produced.
Title:	Conceptual Design/Cost Study of Alternative Methods for Lime/Limestone Scrubbing Waste Disposal
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	TVA
Principal Investigator:	Unknown
Project Description:	This project is one of several tasks comprising the economic studies of major FGD processes being conducted by TVA. In this study several FGD waste disposal methods and FGD system design and operating premises will be selected for a detailed economic evaluation of FGD waste disposal. Currently available information, such as engineering cost estimates from the Aerospace contract and fixation vendor estimates from the Shawnee field evaluation will be used in the initial efforts, with updating as additional information becomes available. Alternatives will very likely include variations in mechanical dewatering equipment, variations in treatment (e.g., oxidation to gypsum, chemical fixation), and variations in ultimate disposal (e.g., ponding, landfill).

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Gypsum By-product Marketing Studies
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	TVA
Principal Investigator:	Unknown
Project Description:	This project is one of several tasks comprising the flue gas desulfurization (FGD) byproduct marketing studies being conducted by TVA. A preliminary study conducted by TVA during early 1974 indicated the possibility that production and sale of abatement gypsum offered a substantial economic advantage over FGD waste disposal. These new studies include a thorough evaluation of gypsum producing processes (e.g., Chyoda, carbon absorption, $CaSO_3$ oxidation) and a detailed U.S. marketing study of abatement gypsum for wallboard. Future plans include studies of abatement gypsum for use in Portland cement manufacture.
Title:	Stack Gas Pollution Control Coordination Center
Contract No.	RP209
Supporting Organization:	EPRI
Performing Organization:	Battelle Memorial Institute
Principal Investigator:	
Project Description:	Battelle recently established an information bank on the status of stack gas cleanup methods being tested on a large scale at power stations. In the current project, Battelle will focus on specific technical problems emerging from the Coordination Center data base and from EPRI/Industry Workshops, and will also define a SO_x control research, development, and testing program that would be most responsive to industry needs. The utility industry is currently operating, constructing, or planning over 90 separate stack gas desulfurization installations.

Table 150 (continued). ON-GOING AND PLANNED ACTIVITIES: FLUE GAS DESULFURIZATION

Title:	Removal of Pollutants from Flue Gases
Contract No.:	
Supporting Organization:	
Performing Organization:	U.S. Department of the Interior
Principal Investigator:	A. J. Forney, W. P. Haynes, J. P. Strakey, G. Cinquegrane, and B. M. Harney
Project Description:	Research into various processes for the removal of SO_x and NO_x.

PARTICULATE CONTROL DEVICES

Research and development directed to particulate control for stationary combustion sources has been focused primarily on electrostatic precipitators. Particulate emissions from stationary combustion are primarily a result of coal combustion. The majority of coal is burned by the utility sector where electrostatic precipitators have been applied to three-quarters of the coal-burning capacity. In recent years EPA has supported many projects directed towards evaluating and improving the performance of electrostatic precipitators. Areas such as resistivity problems, changing flow patterns, rapping losses and efficiency (both mass and fine particulate) have been investigated by EPA and EPA contractors. Much of the work has been performed by Southern Research Institute including development of a mathematical model to predict performance. More recently, EPRI has supported a number of projects directed towards electrostatic precipitator performance and problems in the utility industry.

Installation of lime/limestone SO_2 scrubbers in the coming years may lead to more extensive use of wet scrubbers for partial or complete fly ash removal. Venturi scrubbers will be used in some cases to remove particulates before the stack gases enter the SO_2 scrubber. Some fly ash will be collected in SO_2 scrubbers. EPA is currently investigating the efficiency and economics of wet scrubbers for fly ash collection.

In the last 2 years two utilities have installed fabric filters. GCA/Technology Division has tested fabric filters applied to utility boilers in both Colorado and Pennsylvania under an EPA contract. EPRI is sponsoring further tests of the Colorado installation to be performed by Meteorology Research Institute.

A list of new or continuing projects is presented in Table 151.

Table 151. ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Ionizer/Precipitator Fine Particulate Dust Collection System
Contract No.:	RP386
Supporting Organization:	EPRI
Performing Organization:	Air Pollution Systems, Inc.
Principal Investigator:	Unknown
Project Description:	This 1-year project is directed at accomplishing a more effective collection of low-conductivity fly ash from fossil-fuel-fired boilers and fine particulate matter by imposing a higher degree of ionization on the particles. Scheduled to be completed by December 1975.
Title:	Performance Evaluation of Electrostatic Precipitators
Contract No.:	RP413
Supporting Organization:	EPRI
Performing Organization:	Southern Research Institute
Principal Investigator:	Unknown
Project Description:	Computer model studies will enable new precipitator installations to be analyzed. The mechanisms of electrode failure will be studied. because these failures are a major source of plant outages. The study will also consider ash from oil-fired boilers. Scheduled to be completed by June 1977.
Title:	Simultaneous Removal of Mercury and SO_2 From Combustion and Smelter Flue Gases
Contract No.:	
Supporting Organization:	U.S. EPA
Performing Organization:	South Dakota School of Mines
Principal Investigator:	M. C. Fuerstenav
Project Description:	An evaluation of the feasibility of a process for simultaneously removing both Mercury and SO_2.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Assessment and Development of Control Technology Technology Applicable to Removal of Mercury from SO_2 Bearing Waste Gases
Contract No.	68-02-1097
Supporting Organization:	U.S. EPA
Performing Organization:	Midwest Research Institute
Principal Investigator:	Dr. I. Smith
Project Description:	Literature and bench-scale study of processes for Mercury removal.
Title:	Gas-Flow Modeling for Electrostatic Precipitators
Contract No.	RP531
Supporting Organization:	EPRI
Performing Organization:	Flow Research
Principal Investigator:	Unknown
Project Description:	The objectives of this 3-month project are to: (1) perform a proof-of-concept study for a new fluid dynamic collector, applicable to electrostatic precipitators, that would utilize fluid dynamic forces to retain collected particles and minimize rapping and re-entrainment losses; (2) evaluate the use of scale models and analytic models for the determination of proper gas-flow distribution in electrostatic precipitators; and (3) provide case studies of gas-flow modeling over the range of Reynolds numbers expected. Scheduled to be completed by May 1976.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Electrostatic Precipitator Plate Rapping and Reliability
Contract No.	RP532
Supporting Organization:	EPRI
Performing Organization:	Princeton University
Principal Investigator:	Unknown
Project Description:	The rapping of collector plates and the deposition of the collected ash into hoppers is a key issue in the reduction of size and cost as well as in the improved reliability and efficiency of the electrostatic precipitator for the collection of fine particules. This 1-year project will be a fundamental analysis of the structural mechanics of collector plate impaction and vibration. Scheduled to be completed by December 1977.
Title:	Effects of Smoke- and Corrosion-Suppressant Additives on Particulate and Gaseous Emissions from a Utility Gas Turbine
Contract No.	RP462
Supporting Organization:	EPRI
Performing Organization:	KVB Engineering, Inc.
Principal Investigator:	Unknown
Project Description:	EPRI will perform a research program on a full-scale gas turbine to characterize several metallic-based fuel additives. It is intent of this effort to extract representative exhaust samples from a utility gas turbine for analysis of particulate grain loading, particulate size distribution and composition, opacity, chemical state of the additive-based trace metals, analysis for polycyclic organic matter, and gaseous emission levels with and without fuel additives. Scheduled to be completed by December 1975.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Development of Standard Laboratory Resistivity Apparatus and Procedure for Fine Particulate Characterizations
Contract No.:	RP 464
Supporting Organization:	EPRI
Performing Organization:	Denver Research Institute
Principal Investigator:	Unknown
Project Description:	This 6-month project seeks a relative evaluation of the various methods used to measure the laboratory conductivity of fly ash and, if possible, a determination of the best method to adopt as an EPRI standard for future work. Especially with less than about 1 percent sulfur, the ash conductivity becomes a vital parameter in the determination of the precipitator design. Scheduled to be completed by September 1975.

Title:	Technology Evaluation of Particulate and SO_2 Scrubbing by Alkali Powder Reactor Methods
Contract No.	RP491
Supporting Organization:	EPRI
Performing Organization:	Bechtel Corporation
Principal Investigator:	Unknown
Project Description:	The objectives of this 14-month project are: (1) to evaluate the technology for dry removal of particulates and sulfur dioxide by a contactor of alkali powder; (2) to assess the availability, mining, and transportation of necessary raw materials; (3) to identify those power stations that might benefit from the technology; and (4) to conduct liaison between organizations having special experience with the technology. Two variations of the process are available: dry powdered alkali on a fabric filter and dry granular alkali in a fixed- or moving-bed reactor. Completed April 1975 but additional work is anticipated.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Experimental Investigation of an Electrostatic Precipitator with an Acoustic Preconditioner and Using Resonant Effects
Contract No.:	RP539
Supporting Organization:	EPRI
Performing Organization	State University at Buffalo, New York
Principal Investigator:	Unknown
Project Description:	The objective of this 1-year research project is to provide data sufficient to permit an economic evaluation and design of a resonant acoustic field as a preconditioner for the efficient removal of submicron particles in an electrostatic precipitator. Two experiments will be conducted. In the first, the optimum frequency and intensity for the effective coagulation of particles will be determined. In the second, the power savings in power consumption using resonant acoustic effects will be determined.
Title:	Development of Agglomerator and New Collector for Electrostatic Precipitation
Contract No.:	RP533
Supporting Organization:	EPRI
Performing Organization:	Stanford University
Principal Investigator:	Unknown
Project Description:	This 1-year project involves basic studies into means for the substantial reduction in the size and cost of electrostatic precipitators for the collection of fine particulates from flue gases. Specifically, the project will develop two key items: an agglomerator and a new collector. The agglomerator will collect fine particles by interaction with coarse particles. The new collector will employ advanced electrical and boundary layer gas-flow techniques and will be immunized against the effects of high resistivity western fly ash. Scheduled to be completed by June 1976.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Determination of the Fractional Efficiency, Opacity Characteristics and Engineering and Economic Aspects of a Fabric Filter Operating on a Uility Boiler
Contract No.	RP534
Supporting Organization:	EPRI
Performing Organization:	Meteorological Research, Inc.
Principal Investigator:	Unknown
Project Description:	The purpose of this 10-month project is to perform a complete engineering and economic analysis of the fabric filter at the Nucla Station of Colorado Ute. This will include determination of fabric filter fractional efficiency, opacity characteristics, and an engineering analysis of the economics, reliability, and maintenance of the opacity regulations as a useful framework for comparing fabric filter installations to other fly ash collection devices. Scheduled to be completed by March 1976.
Title:	Use of High Expansion Liquid Foams in Submicron Particle Emission Control
Contract No.	RP362
Supporting Organization:	EPRI
Performing Organization:	Washington State University
Principal Investigator:	Unknown
Project Description:	The objective of this 2-year program is to determine the feasibility of using high-expansion liquid foams to remove submicron particles from stack gases. Existing equipment will be modified and experiments conducted to determine the relationship between operating variables and collection efficiencies. The system will be modeled mathematically.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	R&D Program for the Control of Fine Particulate Emissions from Stationary Sources
Contract No.	
Supporting Organization:	U.S. EPA
Performing Organization:	Midwest Research Institute
Principal Investigator:	L. Shannon
Project Description:	Evaluate existing equipment and new approaches to control fine particulates.
Title:	Wet Precipitator Technology and Joint Collection of SO_x and Particulates
Contract No.	68-02-1313
Supporting Organization:	U.S. EPA
Performing Organization:	Southern Research Institute
Principal Investigator:	Dr. J. P. Gooch
Project Description:	A review and evaluation of wet precipitator technology, particularly with regard to the joint removal of SO_x and Particulates.
Title:	Fractional Efficiency of a Utility Boiler Baghouse
Contract No.:	68-02-1438
Supporting Organization:	U.S. EPA (J. Turner)
Performing Organization:	GCA
Principal Investigator:	R. Bradway
Project Description:	A field testing program to determine the performance of coal-fired utility boiler baghouses at Nucla, Colorado and Sunbury, Pennsylvania. Field Testing was completed in April 1975.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Evaluation of the Controllability of Power Plants to Meet Emission and Air Quality Standards and the Convertibility of Gas and Oil-fired Plants to Coal
Contract No.:	68-02-1477
Supporting Organization:	U.S. EPA
Performing Organization:	Pedco Environmental Specialists, Inc.
Principal Investigator:	Unknown
Project Description:	

Title:	Evaluation of Venturi Scrubber Systems for Control of Particulate Emissions from a Coal-fired Utility Boiler
Contract No.:	68-02-1802
Supporting Organization:	U.S. EPA
Performing Organization:	Meteorology Research, Inc.
Principal Investigator:	
Project Description:	

Title:	Particle Migration Velocities in Electrostatic Precipitators
Contract No.:	RP363
Supporting Organization:	EPRI
Performing Organization:	Washington State University
Principal Investigator:	Unknown
Project Description:	The objective of this 2-year project is to provide information required for better electrostatic precipitator design and to reduce the degree of empiricism. Washington State University is the contractor.

Table 151 (continued). ON-GOING AND PLANNED ACTIVITIES: PARTICULATE CONTROL DEVICES

Title:	Rapping Re-entrainment Losses from Electrostatic Precipitators
Contract No.	68-02-1875
Supporting Organization:	U.S. EPA
Performing Organization:	Southern Research Institute
Principal Investigator:	
Project Description:	
Title:	Fine Particle Charging System Development
Contract No.	68-02-1490
Supporting Organization:	U.S. EPA
Performing Organization:	Southern Research Institute
Principal Investigator:	
Project Description:	

APPENDIX A

FORM 67
STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
FOR THE YEAR ENDED DECEMBER 31, 1972

FPC Form 67
Rev (3-73)

FORM APPROVED*
BUDGET BUREAU
No. 54-R0085

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA FOR THE YEAR ENDED DECEMBER 31, 1972

FULL LEGAL NAME OF RESPONDENT

ADDRESS (Give Number, Street, City, State and Zip Code)

PLANT CODE*
(USE THROUGHOUT THE REPORT)

PLANT NAME

PLANT LOCATION, INCLUDING COUNTY, STATE, NEAREST POST OFFICE, AND ZIP CODE

REPORT TO THE FEDERAL POWER COMMISSION

Note: This statement should be completed and filed in the

FEDERAL POWER COMMISSION
555 Battery Street Room 415
San Francisco California 94111

on or before May 1, 1973

Name, title, and address of officer or other person to whom should be addressed any communication concerning this report

NAME AND TITLE

TELEPHONE NUMBER (Give Area Code)

ADDRESS

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GENERAL INSTRUCTIONS

(1) An original and five-conformed copies of this report form properly filled out and attested shall be filed with the Federal Power Commission on or before the first day of the fifth month following the close of the calendar or fiscal year for each plant operated by an electric utility with a steam-electric generating capacity of 25 megawatts or greater during the year covered, provided the plant is part of an electric utility system with a total capacity of 150 megawatts or more. This report form must also be filed for all plants with a steam-electric generating capacity of 25 megawatts or greater if the plants are located in a National Air Quality Control Region announced by the National Air Pollution Control Administration (Appendix A lists the National Air Quality Control Regions) even if they are part of a system with a total capacity of less than 150 megawatts.

(2) Six copies of the completed form, including the original if the report is typewritten, shall be returned to the Regional Office of the Federal Power Commission indicated on the cover. If more than one sheet is required for any pages label them Sheet 1; Sheet 2; etc. respectively. Retain a copy of the form for your files.

(3) All entries shall be legible and the form shall be suitable for reproduction.

(4) Information shall be furnished for the calendar year. Information on equipment and facilities shall be reported as of the end of the calendar year.

(5) Part I, Schedules A, B, C, and D, and Part II, Schedules A and B should be reported in full each year. Part I, Schedule E, and Part II, Schedules C, D, E, and F, should be completed for 1969 and every fifth year thereafter (1974, 1979, etc.); in the intervening years (1970, 1971, 1972, 1973, 1975, etc.) the data should be reported when equipment was: (a) placed in operation during the year; (b) altered during the year (i.e. installed, remodeled, removed or otherwise changed); or (c) not previously reported.

(6) Actual data are requested; however, estimated or calculated data may be reported, provided all such data are noted. Estimates should be identified by the letters "Est" following the entry, calculated data should be identified by the letters of "Cal." Estimates and calculations should be based on actual operating conditions during the year. If other conditions are assumed for any estimates or calculations, they should be specified in a footnote.

(7) Inconsistencies within this form and with other FPC forms should be explained.

(8) No deviation from these instructions should be undertaken without the approval of the Regional Office of the Federal Power Commission.

(9) Insert the word "none" where it is a true and complete answer to any inquiry. Insert the words "not applicable" in those sections or parts of sections which do not apply.

(10) All accounting words and phrases are to be interpreted in accordance with the Uniform System of Accounts for Public Utilities and Licensees prescribed by the Federal Power Commission. To the extent possible, costs and expenses should be reported in accordance with the above-mentioned Uniform System of Accounts.

GENERAL INSTRUCTIONS (Cont'd)

(11) Additional statements inserted for the purpose of further explanation of sections or items should be made on durable paper conforming to this form in size and width or margin except for the optional plant one-line diagram which may be of a convenient size as chosen by the respondent. Inserts should be securely bound in the report. Inserts should bear the titles of the sections and report form page numbers to which they pertain.

(12) All communications concerning this-form and all requests for extra copies of individual pages should be addressed to the indicated Regional Office of the Commission. Additional copies of the complete form may be obtained from the Federal Power Commission, Washington, D. C. 20426 at 50 cents per copy.

DEFINITIONS

a. "Respondent", wherever used in this report, means the electric utility, regardless of type of ownership, in whose behalf the report is made.

b. The "capacity" of a generating unit is defined as the maximum generator nameplate rating at maximum hydrogen pressure.

c. Boilers having a "common breeching", as used herein, means two or more boilers whose flue gas outlet ducts are connected to the same ductwork and stack.

d. The terminology and criteria for performance of the flue gas cleaning equipment shall be as stated in the standards and publications of the Industrial Gas Cleaning Institute, and the American Society of Mechanical Engineers.

e. The terminology and criteria for performance of cooling towers shall be in accordance with the standards and publications of the Cooling Tower Institute.

f. The terminology and criteria for performance of condensers shall be as stated in the standards and publications of the American Society of Mechanical Engineers.

ABBREVIATIONS

Abbreviations as used herein conform to U. S. National Bureau of Standards Special Publication 304.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA

PART I - AIR QUALITY CONTROL DATA

Schedules A, B, C, and D

Instructions

1. Report annually.
2. Assign the same boiler designation to a specific boiler throughout the entire Part I of the form.
3. All footnotes should be shown on page 12.
4. If more than one sheet is required for any pages label them, for example, as page 5, sheet 1; page 5, sheet 2; etc., respectively.

FPC Form 67
Rev (6-70)

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME		PLANT NAME	REPORT FOR YEAR ENDED DECEMBER 31, 19 ____
COMPANY - PLANT CODE	PLANT CAPACITY - MW	STATE	COUNTY	POST OFFICE AND ZIP CODE

Schedule A - Fuel Quality

SECTION 1 - Plant Fuel Consumption Data

QUALITY REPORTED ON (Check one) :
☐ (B) ... "As burned" basis
☐ (R) ... "As received" basis

Report percent sulfur, ash, and moisture figures as weighted averages for the month to the nearest 0.1 percent (based on weight of fuel consumed). Report fuel quality and Btu values on "as burned" basis; if quality is only available on "as received" basis, it may be so reported. If fuel represents a blend of two or more types of coal or oil with distinctly different qualities, this should be described in a footnote.

LINE NO.	MONTH (a)	COAL					OIL			GAS		CHECK FOR FOOTNOTE* (l)
		CONSUMPTION 1000 Tons (b)	BTU per Pound (c)	AVG. % SULFUR (d)	AVG. % ASH (e)	AVG. % MOISTURE (f)	CONSUMPTION 1000 Bbls (g)	BTU per Gal. (h)	AVG. % SULFUR (i)	CONSUMPTION 1000 Mcf. (j)	BTU per cu. ft. (k)	
01	JAN.											
02	FEB.											
03	MAR.											
04	APR.											
05	MAY											
06	JUNE											
07	JULY											
08	AUG.											
09	SEP.											
10	OCT.											
11	NOV.											
12	DEC.											
13	YEAR											

* [illegible] shown on page 12.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME	COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19 _____
PLANT NAME		

Schedule A - Fuel Quality (Cont'd)

Section 2 - Plant Fuel Source Data

LINE NO.		COAL		OIL			CHECK FOR FOOTNOTE (g)****
				SOURCE			
	(a)	SOURCE (BUREAU OF MINES COAL DISTRICTS)* (b)	QUANTITY 1000 Tons (c)	SUPPLIER ** (d)	REFINERY OR PORT OF ENTRY *** (e)	QUANTITY 1000 Bbls (f)	
14	SOURCE 1						
15	SOURCE 2						
16	SOURCE 3						
17	SOURCE 4						
18	SOURCE 5						
19	SOURCE 6						
20	SOURCE 7						
21	SOURCE 8						
22	ALL OTHER						

* List of Bureau of Mines Coal Districts is attached. If available, give name and location of mines (in footnote on page 12) supplying substantial portions of the coal used at the plant and the quantities supplied by each mine.

** If residual oil is delivered to a company-wide tank farm for distribution to more than one plant, explain in footnote.

*** Indicate refinery by "(R)" before refinery name; Port of entry by "(P)"; Other by "(O)". Explain "Other" in footnote.

**** All footnotes should be shown on page 12.

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA

PART I - AIR QUALITY CONTROL DATA

Schedule B - Operational Data

Instructions

(1) Efficiency of flue gas cleaning equipment (tested or estimated) is to be reported as the percent by weight of solids, or the percent by volume of gases removed from the flue gas when the flue gas cleaning equipment and associated boiler(s) operate at design capacity, and at the capacity factor for the year.

(2) Efficiency of flue gas cleaning equipment shall be reported to the nearest tenth of a percent.

(3) If a unit of flue gas cleaning equipment is multi-purpose indicate the units tested and estimated current efficiency in removing each emittant.

(4) If more than one unit of flue gas cleaning equipment serves a boiler, show the data for each unit and indicate the combined efficiency and net emission rate in a footnote. Report the operations of such combination of units in lines 25 - 31 and indicate in a footnote the types of units that are combined.

(5) For two or more boilers connected with a common breeching:
  (a) Use a separate sheet number 5 for reporting individual boiler fuel consumption and operation during the year.
  (b) If a group of boilers is served by a common fuel feeder so that fuel consumption at the individual boilers is not obtainable, indicate in the appropriate space all boilers so served.

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME	
PLANT NAME	
COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19 _____

SCHEDULE B - OPERATIONAL DATA

A separate sheet (including Sections 1 and 2) should be prepared for each plant boiler.

01 Section 1 - Fuel Consumption at Boiler No. __________ *

LINE NO.	MONTH (a)	COAL (1000 Tons) (b)	OIL (1000 Bbls) (c)	GAS (1000 Mcf) (d)	CHECK FOR FOOTNOTE** (e)
02	JANUARY				
03	FEBRUARY				
04	MARCH				
05	APRIL				
06	MAY				
07	JUNE				
08	JULY				
09	AUGUST				
10	SEPTEMBER				
11	OCTOBER				
12	NOVEMBER				
13	DECEMBER				
14	TOTAL YEAR				

15 Section 2 - Boiler Operation During Year, Boiler No. __________

Enter as appropriate the following codes 1 thru 7 in columns (b), (c), (d), and (e), lines 16, 17 and 18; Actual hours of system peak need not be shown.

Boiler Operation	Code	Boiler Operation	Code
Continuous nominal full load	1	No-load hot standby	5
Less than full but over 75% load . . .	2	No-load cold standby	6
50% - 75% load	3	Other (explain in footnote, pg. 12) . .	7
Under 50% load	4		

LINE NO.	During Period of System (a)	WEEKDAYS: Average for consecutive four hours of highest output (Code only) (b)	WEEKDAYS: Average for consecutive four hours of lowest output (Code only) (c)	WEEKENDS ***: Average for consecutive four hours of highest output (Code only) (d)	WEEKENDS ***: Average for consecutive four hours of lowest output (Code only) (e)	CHECK FOR FOOTNOTE ** (f)
16	WINTER PEAK WEEK					
17	SUMMER PEAK WEEK					
18	LOWEST POWER PERIOD WEEK					
19	TOTAL HOURS OF BOILER OPERATION DURING YEAR					
20	BOILER CAPACITY FACTOR, AVERAGE DURING YEAR, PERCENT					

* If fuel consumption is for a group of boilers served by a common fuel feeder, please indicate in footnote, line 14; List all boiler numbers sharing the same fuel feeder (___,___,___,___). Common fuel feeder may be shown on plant one-line diagram.

** All footnotes should be shown on page 12.

*** Midnight Friday to midnight Sunday.

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ________

SCHEDULE B - OPERATIONAL DATA (Cont'd)

Section 3 - Flue Gas Cleaning Equipment

LINE NO.	(a)	BOILER NO. (b)	BOILER NO. (c)	BOILER NO. (d)	BOILER NO. (e)	CHECK FOR FOOTNOTE ** (f)
21	BOILER NUMBER					
	MECHANICAL SEPARATORS:					
22	TESTED EFFICIENCY					
23	DATE OF TEST (YEAR/MONTH/DAY)					
24	ESTIMATED EFFICIENCY AT ANNUAL OPERATING FACTOR (If no test during year)					
	ELECTROSTATIC OR COMBINATION MECHANICAL-ELECTRICAL PRECIPITATORS:					
25	TYPE (Code "E" for Electrostatic, or "C" for Combination)					
26	TOTAL HOURS FOR THE YEAR DURING WHICH ALL ELECTRICAL BUS SECTIONS ARE ENERGIZED AND WHILE BOILER IS OPERATING *					
27	TESTED EFFICIENCY					
28	DATE OF TEST (YEAR/MONTH/DAY)					
29	STATE NUMBER OF HOURS DURING YEAR WHEN PRECIPITATOR IS NOT FULLY OPERATIONAL WHILE BOILER IS OPERATING.					
30	ESTIMATED EFFICIENCY DURING PERIODS WHEN BOILER IS OPERATING BUT WHEN PRECIPITATOR IS NOT FULLY OPERATIONAL					
31	ESTIMATED EFFICIENCY AT ANNUAL OPERATING FACTOR (If no test during year) *					
	DESULFURIZATION SYSTEM: ***					
32	HOURS OF SERVICE DURING YEAR * ..					
33	TESTED EFFICIENCY					
34	DATE OF TEST (YEAR/MONTH/DAY) ...					
35	ESTIMATED EFFICIENCY AT ANNUAL OPERATING FACTOR (If no test during year)*					
	OTHER FLUE GAS CLEANING TYPE (Explain in footnote)					
36	HOURS IN SERVICE DURING YEAR*					

* Explain in footnote unusual operating conditions

** All footnotes should be shown on page 12.

*** When operational

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME	
PLANT NAME	
COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19 ________

SCHEDULE C - Disposal of Products Collected from Combustion Cycle at Plant

LINE NO.	(a)	LIMESTONE (b)	DOLOMITE (c)	OTHER ** (d)	CHECK FOR FOOTNOTE (e) ***
01	AMOUNT OF ADDITIVES USED (1000 tons)*				

LINE NO.	PRODUCT (a)	QUANTITIES (1000 tons)*						CHECK FOR FOOTNOTE (h) ***
		TOTAL COLLECTED **** (b)	SOLD (c)	PAID DISPOSAL (d)	LAND FILL (e)	WATER DISPOSAL (f)	OTHER DISPOSAL (g)	
02	FLYASH							
03	BOTTOM ASH							
04	ELEMENTAL SULFUR							
05	SULFURIC ACID *****							
06	SULFUR DIOXIDE							
07	OTHER SULFUR PRODUCTS**							
08	OTHER PRODUCTS **							

* Report all quantities to nearest 0.1 thousand tons.

** Specify in footnote

*** All footnotes should be shown on page 12.

**** Total of products collected (column "b") should approximate the sum of columns "c" through "g".

***** Enter purity of acid _______ % by weight.

SCHEDULE D - Air Quality Control, Plant Operation and Maintenance Expenses

LINE NO.	CHARGED TO: (a)	AMOUNT ($1000) (b)	CHECK FOR FOOTNOTE 1/ (c)
		$	
09	FLYASH COLLECTION AND DISPOSAL		
10	BOTTOM ASH COLLECTION AND DISPOSAL		
11	SULFUR AND SULFUR PRODUCT COLLECTION AND DISPOSAL		
12	COLLECTION AND DISPOSAL OF OTHER PRODUCTS FROM FLUE GAS (SPECIFY IN FOOTNOTE)		
13	OTHER AIR QUALITY CONTROL EXPENSES (SPECIFY IN FOOTNOTE)		
14	TOTAL AIR QUALITY CONTROL EXPENSE (TOTAL OF LINES 09 THROUGH 13)		
	REVENUES FROM AIR QUALITY CONTROL OPERATIONS:		
15	SALES OF FLYASH (IF SOLD AS FLYASH)		
16	SALES OF BOTTOM ASH (IF SOLD AS BOTTOM ASH)		
17	SALES OF FLYASH AND BOTTOM ASH (IF SOLD INTERMINGLED)		
18	SALES OF SULFUR AND SULFUR PRODUCTS		
19	OTHER REVENUES FROM AIR QUALITY CONTROL OPERATIONS (SPECIFY IN FOOTNOTE)		
20	TOTAL BY-PRODUCT SALES REVENUE FROM AIR QUALITY CONTROL OPERATIONS (TOTAL OF LINES 15 THROUGH 19)		

1/ All footnotes should be shown on page 12.

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA

PART I - AIR QUALITY CONTROL DATA

INSTRUCTIONS - Schedule E - Equipment (Design Parameters)

1. Report every five years, or as specified in item (5) of General Instructions, page ii.

2. Report separate data for each boiler and stack: Indicate which equipment and stack(s) are connected to which boiler by showing data for connected equipment in the same column.

3. Fuel consumption should be reported as follows: Coal in tons per hour, Oil in barrels per hour, Gas in thousand cubic feet per hour.

4. Total air flow during full load is to be reported in standard cubic feet per minute and also in terms of the percent of theoretical stoichiometric at 60°F and atmospheric pressure.

5. If more than one unit of one category of flue gas cleaning equipment serves a boiler, show the data for each unit and indicate the combined efficiency and the net emission rate.

6. If a unit of flue gas cleaning equipment is multipurpose, indicate the efficiency and the mass emission rate for each emittant.

7. Design efficiency of flue gas cleaning equipment is to be stated as the percent by weight of emittant removed from the flue effluent when a plant and flue gas cleaning equipment and the associated boiler(s) operate at design capacity.

8. The design mass emission rate should be expressed in pounds of particulate matter or pounds of SO_2 (sulfur dioxide) per hour at the outlet from the flue gas cleaning equipment. It should be expressed in pounds of particulate or in pounds of specified other material collected under design conditions of both the plant and the flue gas cleaning equipment and the associated boiler(s), using current fuels.

9. The flue gas rate should be expressed in terms of actual cubic feet per minute at the top of the stack.

10. The exit gas temperature should be expressed in degrees Fahrenheit at the top of the stack.

11. The exit gas velocity should be expressed in feet per second at the top of the stack.

12. Cost should be reported as the original costs recorded on the utility's books of accounts and unitized as prescribed in the FPC List of Units of Property effective January 1, 1961. It is realized certain items called for in this report are not specifically unitized in the referenced list of property units. In this case the most accurate figure available is desired. In the case of stacks without foundation, include the stack cost plus those added costs which are essential to the stack operation and support.

13. All footnotes should be shown on page 12.

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ______

SCHEDULE E - Equipment (Design Parameters)

PLEASE CIRCLE THE APPROPRIATE NUMBER:
(1) Regular Plant Report
(2) Placed in Operation during year
(3) Altered during year
(4) Not previously reported
(5) Amended report

LINE NO.	Section 1 - Boiler Data (a)	BOILER NO. (b)	BOILER NO. (c)	BOILER NO. (d)	BOILER NO. (e)	CHECK FOR FOOTNOTE** (f)
01	BOILER NUMBER(S)					
02	SERVED BY STACK NUMBER					
03	RELATED TO GENERATOR NUMBER					
04	BOILER MANUFACTURER (Code as shown below)*					
05	YEAR BOILER PLACED IN SERVICE					
06	ASSOCIATED TURBO-GENERATING CAPACITY (Megawatts)					
07	MAXIMUM CONTINUOUS STEAM CAPACITY (Thousand pounds/hour)					
	DESIGN FUEL CONSUMPTION: 100% RATING					
08	COAL (Tons/hour)					
05	RESIDUAL OIL (Barrels/hour)					
10	GAS (Thousand cubic feet/hour)					
	PERCENT BOILER EFFICIENCY					
11	AT 100% LOAD					
12	AT 75% LOAD					
13	AT 50% LOAD					
	AIR FLOW AT 100% LOAD					
14	TOTAL AIR, STANDARD CUBIC FEET/MINUTE (Incl. Excess Air)					
15	PERCENT EXCESS AIR USED					
16	WET OR DRY BOTTOM - (Code as "Wet" or "Dry")(For Coal only)					
17	FLYASH REINJECTION - (Code "Yes" or "No")					
18	TYPE OF FIRING (Code as shown below)***					

* BOILER MANUFACTURERS:

B&W	The Babcock & Wilcox Co.
CE	Combustion Engineering, Inc.
ERIC	Erie City Iron Works
FW	Foster Wheeler Corp.
RILY	Riley Stoker Corp.
VOGT	Henry Vogt Machine Co., Inc.
OTHE	Other (Specify in footnote)

** All footnotes should be shown on page 12.

*** TYPE OF FIRING (where applicable, use more than one code):

PCFR	Pulverized Coal: Front Firing
PCOP	Pulverized Coal: Opposed Firing
PCTA	Pulverized Coal: Tangential Firing
CYCL	Cyclone
SPRE	Spreader Stoker
OSTO	Other Stoker
FLUI	Fluidized Bed
RFRO	Residual Oil: Front Firing
ROPP	Residual Oil: Opposed Firing
RTAN	Residual Oil: Tangential Firing
GFRO	Gas: Front Firing
GOPP	Gas: Opposed Firing
GTAN	Gas: Tangential Firing
OTHE	Other (Specify in footnote)

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ______

SCHEDULE E - Equipment (Design Parameters) - Continued

Section 2 - Flue Gas Cleaning Equipment Data

LINE NO.	(a)	BOILER NO. (b)	BOILER NO. (c)	BOILER NO. (d)	BOILER NO. (e)	CHECK FOR FOOTNOTE (f) 1/
	BOILER NUMBERS (Enter same Boiler Numbers as indicated on page 5, line 01)					
	FLUE GAS CLEANING EQUIPMENT MECHANICAL COLLECTORS					
19	TYPE (Code as shown below)*					
20	DESIGN EFFICIENCY (Percent)					
21	MASS EMISSION RATE (Pounds per hour)**					
22	YEAR PLACED IN SERVICE					
23	INSTALLED COST (Thousands of dollars)***					
24	MANUFACTURER (Code as shown below)****					
	ELECTROSTATIC AND COMBINATION MECHANICAL-ELECTRICAL PRECIPITATORS					
25	TYPE (Code as "E" or "C")					
26	DESIGN EFFICIENCY (Percent)					
27	MASS EMISSION RATE (Pounds per hour)**					
28	YEAR PLACED IN SERVICE					
29	INSTALLED COST (Thousands of dollars)***					
30	MANUFACTURER (Code as shown below)****					
	DESULFURIZATION SYSTEM					
31	TYPE (Indicate by footnote)					
32	DESIGN EFFICIENCY (Percent)					
33	MASS EMISSION RATE (Pounds per hour)**					
34	YEAR PLACED IN SERVICE					
35	INSTALLED COST (Thousands of dollars)***					
36	MANUFACTURER (Specify in footnote)					
	OTHER FLUE GAS CLEANING EQUIPMENT					
37	TYPE (Indicate by footnote)					
38	DESIGN EFFICIENCY (Percent)					
39	MASS EMISSION RATE (Pounds per hour)**					
40	YEAR PLACED IN SERVICE					
41	INSTALLED COST (Thousands of dollars)***					
42	MANUFACTURER (Specify in footnote)					

1/All footnotes should be shown on page 12.

* Mechanical Collectors - Type (If more than one type is used in a series, indicate all applicable codes and explain in footnote).

GRAV - Gravitational or baffled chamber
SCTA - Single cyclone-Conventional reverse flow, tangential inlet
SCAX - Single cyclone-Conventional reverse flow, axial inlet
MCTA - Multiple cyclones-Conventional reverse flow; tangential inlet.
MCAX - Multiple cyclones-Conventional reverse flow; axial inlet
CYCL - Straight-through-flow cyclones
IMPE - Impeller collector
VENT - Wet collector: Venturi
WETC - Wet Collector: Other (Specify in footnote)
BAGH - Baghouse (Fabric Collector)
OTHE - Other (Specify in footnote)

** Pounds per hour = $\dfrac{\text{Grains/Actual Cu.Ft./ x /Actual Cu.Ft.Vol./Hr./}}{\text{7000/Grains/Pound}}$

*** See Instruction 12, page 8.

**** Flue Gas Cleaning Equipment Manufacturers (See page 11 for Codes)

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME	
PLANT NAME	
COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19 ______

SCHEDULE E - Equipment (Design Parameters) - Continued

Section 3 - Stack Data

LINE NO.	(a)	STACK NUMBER (b)	STACK NUMBER (c)	STACK NUMBER (d)	STACK NUMBER (e)	CHECK FOR FOOTNOTE* (f)
43	STACK NUMBERS					
44	INSTALLED COST (Thousands of dollars)(Instruction 12, page 8)					
45	STACK HEIGHT (Feet above Ground Elevation)					
46	INSIDE DIAMETER OF FLUE AT TOP (Inches)					
	FLUE GAS RATE (CUBIC FEET/MINUTE)					
47	AT 100% LOAD					
48	AT 75% LOAD					
49	AT 50% LOAD					
	EXIT GAS TEMPERATURE (DEGREES FARENHEIT)					
50	AT 100% LOAD					
51	AT 75% LOAD					
52	AT 50% LOAD					
	EXIT GAS VELOCITY (FEET/SECOND)					
53	AT 100% LOAD					
54	AT 75% LOAD					
55	AT 50% LOAD					
56	DISTANCE TO NEXT STACK, CENTER TO CENTER (FEET)**					
57	ORIENTATION OF LINE OF STACKS - DEGREES CLOCKWISE FROM TRUE NORTH**					

* All footnotes should be shown on page 12.

** Show position of stacks by stack number to correspond with the identification in line 43. Enter true north on the diagram.

Stacks Orientation Diagram:

FLUE GAS CLEANING EQUIP. MANUFACTURERS (See pg. 10)

AAFC - American Air Filter Co., Inc.
AMST - American Standard, Inc.
BELC - Belco Pollution Control Corp.
BUEL - Buell Engineering Co., Inc.
DUCO - The Ducon Co., Inc.
FIKL - Fischer-Klosterman, Inc.
FULL - Fuller Co., Draco Products
KIRK - Kirk & Blum Manufacturing Co.
KOPP - Koppers Co., Inc.
PPCI - Precipitair Pollution Control, Inc.
PAOA - Precipitation Associates of America, Inc.
PLVR - Pulverizing Machinery Division
COTT - Research Cottrell, Inc.
SVRS - Severny Electronatom Corp.
UOP UOP Air Correction Division
TORI - The Torit Corp.
WEST - Western Precipitation Division
WHEE - Wheelabrator Corp.
ZURN - Zurn Industries, Inc.
OTHE - Other (Specify in footnote)

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ______

FOOTNOTES

FOOTNOTE FOR:			FOOTNOTE	
PAGE	SHEET	LINE	COLUMN	TEXT

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA

PART II - WATER QUALITY CONTROL DATA

(Applicable to Nuclear and Fossil Fueled Steam-Electric Plants)

Schedules A and B

Instructions

1. Report annually.
2. All footnotes should be shown on page 20.
3. General instructions on pages i and ii also apply to this part of the form.

Schedule A - Operational Data

Instructions

1. In Section 1, the cooling water withdrawals should include amounts taken from lakes, reservoirs, streams, wells, estuaries and the ocean. When a utility-owned cooling pond is used, show only the makeup quantities taken from the supplying water bodies. The discharges should include the amounts of water returned to the water bodies.
2. In Section 2, the maximum temperature "at diversion" refers to the water temperature in the water body prior to any effect by the plant or diverting facilities. The maximum temperature "at outfall" refers to the water temperature of the cooling water immediately before it joins the water body. It includes the effects of all devices used to reduce the temperature.

Schedule B - Operation and Maintenance Expenses

Instructions

1. The operation and maintenance expenses in Section 1 should include such expenses for pumps, ponds, cooling towers, fans, cooling water intakes and outlets, piping, and other costs associated with cooling water operation. The operation and maintenance expenses for condenser operation should not be included. Costs should be in accordance with the FPC Uniform System of Accounts prescribed for Public Utilities and Licensees.
2. The cost of chemical additives should be excluded from the operation and maintenance expenses and shown separately as indicated.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA
(Applicable to Nuclear and Fossil Fueled Steam-Electric Plants)

COMPANY NAME			REPORT FOR YEAR ENDED DECEMBER 31, 19 ____
PLANT NAME			COMPANY - PLANT CODE
PLANT CAPACITY - MW	STATE	COUNTY	POST OFFICE AND ZIP CODE

SCHEDULE A - OPERATIONAL DATA

Section 1 - Average Annual Cooling Water Use of Plant - CFS

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
01	AVERAGE RATE OF WITHDRAWAL FROM WATER BODY DURING YEAR		
02	AVERAGE RATE OF DISCHARGE TO WATER BODY DURING YEAR		
03	AVERAGE RATE OF CONSUMPTION DURING YEAR		

Section 2 - Maximum Water Temperatures and Average Stream Flows During Months of Winter and Summer System Peak Power Loads

	WINTER PEAK LOAD MONTH ________ **			SUMMER PEAK LOAD MONTH ________ **			
LINE NO.	MAXIMUM TEMPERATURE °F		MONTHLY AVERAGE FLOW IN RECEIVING WATER BODY, CFS	MAXIMUM TEMPERATURE °F		MONTHLY AVERAGE FLOW IN RECEIVING WATER BODY, CFS	CHECK FOR FOOTNOTE *
	AT DIVERSION (a)	AT OUTFALL (b)	(c)	AT DIVERSION (d)	AT OUTFALL (e)	(f)	(g)
04							

Section 3 - Amount of Chemicals used During the Year

LINE NO.	(a)	PHOSPHATE LBS. (b)	CAUSTIC SODA LBS. (c)	HYDRAZINE GALS. (d)	LIME LBS. (e)	ALUM. LBS. (f)	CHLORINE LBS. (g)	OTHER (h)	CHECK FOR FOOTNOTE * (i)
05	COOLING WATER								
06	BOILER WATER MAKEUP								

SCHEDULE B - OPERATION AND MAINTENANCE EXPENSES, $1,000

Section 1 - Cooling Water Operation at Plant

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
07	ANNUAL OPERATION AND MAINTENANCE EXPENSES		
08	ANNUAL COST OF CHEMICAL ADDITIVES		

Section 2 - Boiler Water Makeup and Boiler Blowdown Treatment

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
09	ANNUAL OPERATION AND MAINTENANCE EXPENSES		
10	ANNUAL COST OF CHEMICAL ADDITIVES		

* All footnotes should be shown on page 20.
** Specify month.

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA

PART II - WATER QUALITY CONTROL DATA

Instructions

Schedules C, D, E, and F

1. Report every five (5) years, or as specified in item (5) of General Instructions, page i.

2. If more than one sheet is required for any pages label them, for example, as page 16, sheet 1; page 16, sheet 2; respectively.

3. Assign the same unit designation to a specific unit throughout the entire Part II of the form.

4. All footnotes should be shown on page 20.

Schedule C - Water Use Authority and Limiting Criteria

1. Footnote and explain if equipment for monitoring cooling water temperatures is located at other than points of diversion and outfall.

2. If requested distances do not properly define mixing zone, footnote and describe in necessary detail.

Schedule D - Cooling Facilities

1. In Section 1, footnote and explain any seasonal use of cooling facilities.

2. Show by footnote in Section 3 if spray ponds are used.

3. The costs called for in Sections 2, 3, and 4 should be reported as the original costs reported on the utility's books of accounts and unitized as prescribed in the FPC List of Units of Property effective January 1, 1961. In case certain items are not specifically unitized in the referenced list of property units, the most accurate figure available is desired. The costs should include amounts for such items as pumps, piping, canals, ducts, intake and discharge structures, dams and dikes, reservoirs, cooling towers, and appurtenant equipment. The costs of condensers should not be included.

4. In Section 4, show the water cooling range as the number of degrees (F) the water is designed to be cooled in the cooling equipment.

Schedule E - Cooling Water Supply

1. The dependable flow requested is the seven-day average low flow discharge expected to occur not more frequently than once in 10 years.

2. In Section 2, include such other uses of cooling ponds as fishing, boating, camping, hiking, residential development, and industrial development.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA

COMPANY NAME	
PLANT NAME	
COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19____

SCHEDULE C - WATER USE AUTHORITY AND LIMITING CRITERIA

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
01	ISSUING AUTHORITIES OF LICENSES OR PERMITS: COUNTY, STATE, FEDERAL, OR OTHER. LIST AND DESCRIBE AUTHORITIES IN FOOTNOTE.		
02	FREQUENCY OF TEMPERATURE MONITORING OF COOLING WATER EFFLUENT: CONTINUOUSLY (C), HOURLY (H), DAILY (D), OR OTHER (O). FOOTNOTE AND EXPLAIN IF OTHER.		
03	DISTANCE MIXING ZONE EXTENDS DOWNSTREAM, FT.		
04	DISTANCE MIXING ZONE EXTENDS FROM SHORE, FT.		

LINE NO.	(a)	SUMMER (b)	WINTER (c)	CHECK FOR FOOTNOTE * (d)
	MAXIMUM ALLOWABLE TEMPERATURE RISE OF COOLING WATER (°F)			
05	AT OUTFALL TO RECEIVING WATER BODY			
06	AT LIMITS OF DEFINED MIXING ZONE			
	MAXIMUM ALLOWABLE TEMPERATURE OF COOLING WATER (°F)			
07	AT OUTFALL TO RECEIVING WATER BODY			
08	AT LIMITS OF DEFINED MIXING ZONE			

SCHEDULE D - COOLING FACILITIES

SECTION 1 - GENERAL DESIGN DATA

LINE NO.	(a)	(b)	(c)	(d)	(e)	CHECK FOR FOOTNOTE * (f)
09	GENERATING UNIT IDENTIFICATION NUMBER					
10	RATED GENERATING CAPACITY, MW					
11	TYPE COOLING: ONCE-THROUGH, FRESH (OTF): ONCE-THROUGH, SALINE (OTS): COOLING POND (CP): WET COOLING TOWER (WCT): DRY COOLING TOWER (DCT): COMBINATION (CB). FOOTNOTE AND EXPLAIN COMBINATIONS.					
12	YEAR COOLING FACILITIES INSTALLED					
13	DESIGNED TEMPERATURE RISE ACROSS THE CONDENSER, °F					
14	DESIGNED RATE OF FLOW THROUGH THE CONDENSER, CFS					

* ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.

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COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19____

SCHEDULE D - COOLING FACILITIES - Continued

SECTION 2 - ONCE THROUGH COOLING

LINE NO.	(a)	(b)	(c)	(d)	(e)	CHECK FOR FOOTNOTE * (f)
15	DESIGNED RATE OF WITHDRAWL AT FULL LOAD, CFS					
16	INTAKE LOCATIONS: 1/ DIRECTION FROM CENTER OF PLANT, DEGREES					
17	DISTANCE FROM CENTER OF PLANT, FT.					
18	DISTANCE FROM SHORE, FT.					
19	AVERAGE DISTANCE BELOW WATER SURFACE, FT.					
20	OUTFALL LOCATIONS: 1/ DIRECTION FROM CENTER OF PLANT, DEGREES					
21	DISTANCE FROM CENTER OF PLANT, FT.					
22	DISTANCE FROM SHORE, FT.					
23	AVERAGE DISTANCE BELOW WATER SURFACE, FT.					
24	ARE DIFFUSERS USED? FOOTNOTE AND DESCRIBE IF "YES."					
25	INSTALLED COSTS, $1,000 **					

SECTION 3 - COOLING PONDS

LINE NO.	(a)	(b)	(c)	(d)	(e)	CHECK FOR FOOTNOTE * (f)
26	TOTAL SURFACE AREA, ACRES					
27	TOTAL VOLUME, ACRE-FEET					
28	INSTALLED COSTS, $1,000 **					

SECTION 4 - COOLING TOWERS

LINE NO.	(a)	(b)	(c)	(d)	(e)	CHECK FOR FOOTNOTE * (f)
29	TYPE DRAFT-MECHANICAL (M), NATURAL (N)					
30	LENGTH, IF APPLICABLE, FEET					
31	WIDTH OR DIAMETER AT BASE, FEET					
32	HEIGHT, FEET					
33	WATER COOLING RANGE, °F					
34	INSTALLED COSTS, $1,000 **					

1/ ALTHOUGH NOT REQUIRED, A SKETCH SHOWING THE LAYOUT OF THE COOLING SYSTEM IS DESIRABLE.
* ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.
** See instruction 3, Schedule D, page 15.

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STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19____

SCHEDULE E - COOLING WATER SUPPLY

SECTION 1 - ONCE THROUGH COOLING

LINE NO.	SOURCE(S) OF WATER (a)	7-DAY, 10 YEAR DEPENDABLE FLOW CFS (b)	AVERAGE FLOW CFS (c)	GENERATING UNITS SERVED				CHECK FOR FOOTNOTE * (h)
				NO (d)	NO (e)	NO (f)	NO (g)	
01								
02								
03								

FOOTNOTE AND EXPLAIN ANY DISCHARGE INTO A DIFFERENT BODY OF WATER, AND WHEN DISCHARGE IS OTHER THAN DOWNSTREAM FROM WATER INTAKE LOCATION.

SECTION 2 - COOLING PONDS

LINE NO.	SOURCE(S) OF WATER (a)	7-DAY, 10 YEAR DEPENDABLE FLOW CFS (b)	AVERAGE FLOW CFS (c)	GENERATING UNITS SERVED				CHECK FOR FOOTNOTE * (h)
				NO (d)	NO (e)	NO (f)	NO (g)	
04								
05								
06								
07	PERIOD OF YEAR POND IS USED FOR COOLING							
08	OTHER USES OF POND							

SECTION 3 - COOLING TOWERS

LINE NO.	TOWER NO. (a)	SOURCE(S) OF MAKEUP WATER (b)	PERIOD OF YEAR USED FOR COOLING (c)	LOCATION OF BLOWDOWN DISCHARGE (d)	GENERATING UNITS SERVED				CHECK FOR FOOTNOTE * (i)
					NO (e)	NO (f)	NO (g)	NO (h)	
09									
10									
11									
12									
13									

* ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA

COMPANY NAME	
PLANT NAME	
COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19_____

SCHEDULE F - WATER TREATMENT

SECTION 1 - SETTLING PONDS FOR BOILER WATER BLOWDOWN

LINE NO.		EVACUATION PROCEDURE AND FREQUENCY OF CLEANING		ESTIMATED		DISCHARGE VOLUME CU. FT. PER YR.	NAME OF WATER BODY RECEIVING THE DISCHARGE	CHECK FOR FOOTNOTE •
		METHOD	(TIMES PER YEAR)	p^H	SUSPENDED SOLIDS PPM			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
01	FIRST POND							
02	SECOND POND							

SECTION 2 - SETTLING PONDS FOR BOTTOM ASH

LINE NO.		EVACUATION PROCEDURE AND FREQUENCY OF CLEANING		ESTIMATED		DISCHARGE VOLUME CU. FT. PER YR.	NAME OF WATER BODY RECEIVING THE DISCHARGE	CHECK FOR FOOTNOTE •
		METHOD	(TIMES PER YEAR)	p^H	SUSPENDED SOLIDS PPM			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
03	FIRST POND							
04	SECOND POND							

LINE NO.		SOURCE OF SLUICING AND CLEANING WATER	AMOUNT OF ASH TREATED TONS PER YEAR	CHECK FOR FOOTNOTE •
	(a)	(b)	(c)	(d)
05	FIRST POND			
06	SECOND POND			

SECTION 3 - PROVISIONS FOR PLANT SEWAGE DISPOSAL

LINE NO.	(a)	CODE (b)	CHECK FOR FOOTNOTE • (c)
07	CODE FOR PUBLIC SEWER (PS), SEPTIC TANK (ST) SURFACE WATER BODY (SW), OR OTHER (OT). FOOTNOTE IF OTHER AND EXPLAIN.		

LINE NO.	EFFLUENT TREATMENT DESIGN• (a)	BOD PPM (b)	p^H (c)	PHOSPHATES PPM (d)	OTHER (e)	CHECK FOR FOOTNOTE • (f)
08	BEFORE TREATMENT					
09	AFTER TREATMENT					
10	WATER BODY RECEIVING THE DISCHARGE					

• ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.

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APPENDIX B

FUEL CONSUMPTION BY MAJOR USE CATEGORIES AND LOCATION

This appendix provides information concerning the consumption of various fuels used by the electric utility, industrial, commercial/institutional and residential use categories. Data are presented for fuel use by state and region.

The purpose of these tables is to provide input data on a statewide basis to the priority model. The ratio of state to national fuel consumption can be used to estimate emissions by state from national emissions presented in the summary tables.

Table 152. ELECTRIC UTILITY FUEL CONSUMPTION BY STATE

	External combustion						Internal combustion	
	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Lignite 10^3 tons/yr	Residual oil 10^3 gal/yr	Distillate oil 10^3 gal/yr	Gas 10^6 ft/yr	Oil 10^3 gal/yr	Gas 10^6 ft/yr
U.S. total	372,598	1,460	12,500	19,584,050	1,117,817	3,124,690	2,229,210	265,214
New England	1,107	0	0	3,231,415	5,232	9,940	102,325	797
Connecticut	29	0	0	1,138,103	4,826	0	35,470	0
Maine	0	0	0	189,800	0	0	6,250	626
Massachusetts	13	0	0	1,733,534	0	6,600	43,728	0
New Hampshire	1,031	0	0	77,823	0	0	5,341	171
Rhode Island	0	0	0	92,000	406	1,900	1,532	0
Vermont	34	0	0	155	0	1,440	9,999	0
Middle Atlantic	45,236	1,460	0	5,430,934	0	25,800	1,051,217	35,021
New Jersey	2,349	0	0	1,552,979	0	7,700	406,392	7,279
New York	5,716	0	0	3,199,897	0	12,700	472,393	25,371
Pennsylvania	37,171	1,460	0	678,058	0	5,400	172,432	2,371
East North Central	131,589	0	0	732,741	140,871	103,400	357,442	63,095
Illinois	32,255	0	0	252,296	48,561	26,700	182,820	15,993
Indiana	26,700	0	0	21,950	16,310	9,100	7,735	4,731
Michigan	19,614	0	0	362,078	51,815	33,000	61,772	22,779
Ohio	43,048	0	0	59,229	11,568	13,200	75,539	7,358
Wisconsin	9,972	0	0	37,188	12,617	21,400	29,576	12,234
West North Central	27,816	0	6,400	120,047	75,567	330,700	92,628	33,345
Iowa	2,845	0	0	9,723	14,667	53,800	11,482	6,832
Kansas	1,031	0	0	42,534	12,524	158,200	12,470	5,896
Minnesota	6,898	0	0	37,769	27,398	31,200	45,893	9,009
Missouri	15,358	0	0	19,059	11,048	41,700	12,255	5,892
Nebraska	1,329	0	0	4,571	8,814	42,700	9,416	4,832
North Dakota	0	0	6,400	77	440	0	179	380
South Dakota	355	0	0	6,314	676	3,100	933	504
South Atlantic	75,230	0	0	5,630,587	45,833	186,820	450,345	48,800
Delaware	928	0	0	229,131	3,202	640	8,841	248
District of Columbia	260	0	0	210,654	0	0	11,100	0
Florida	6,553	0	0	2,663,385	0	132,000	138,346	21,221
Georgia	10,710	0	0	135,155	7,690	37,400	122,024	5,324

Table 152 (continued). ELECTRIC UTILITY FUEL CONSUMPTION BY STATE

	External combustion						Internal combustion	
	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Lignite 10^3 tons/yr	Residual oil 10^3 gal/yr	Distillate oil 10^3 gal/yr	Gas 10^6 ft/yr	Oil 10^3 gal/yr	Gas 10^6 ft/yr
South Atlantic								
Maryland	3,865	0	0	978,505	0	3,500	66,356	9,938
North Carolina	19,636	0	0	212,939	14,643	390	27,096	314
South Carolina	5,446	0	0	159,830	17,524	12,200	31,351	9,126.
Virginia	4,933	0	0	1,018,365	2,774	320	44,451	2,637
West Virginia	22,899	0	0	22,623	0	370	780	0
East South Central	62,387	0	0	84,253	169,851	44,690	55,094	8,999
Alabama	18,513	0	0	0	0	4,900	37,694	0
Kentucky	22,037	0	0	4,687	909	4,990	246	422
Mississippi	1,181	0	0	79,566	168,942	34,800	3,130	7,645
Tennessee	20,656	0	0	0	0	0	14,024	931
West South Central	2,696	0	5,700	682,706	410,146	1,960,800	10,795	22,702
Arkansas	0	0	0	318,769	13,850	38,800	751	427
Louisiana	0	0	0	143,096	172,380	334,000	3,775	3,725
Oklahoma	2	0	0	7,476	3,399	283,000	3,406	7,365
Texas	2,694	0	5,700	213,365	220,517	1,305,000	2,863	11,183
Mountain	23,017	0	400	77,319	230,868	185,540	38,820	22,287
Arizona	463	0	0	232	195,770	25,600	29,012	14,317
Colorado	4,321	0	0	25,024	1,890	63,300	5,740	2,276
Idaho	0	0	0	0	0	8	52	0
Montana	585	0	400	2,750	5,808	0	750	1,596
Nevada	3,812	0	0	18,788	5,656	28,200	943	2,122
New Mexico	7,415	0	0	15,069	21,320	64,600	911	1,352
Utah	971	0	0	12,667	424	3,100	195	161
Wyoming	5,450	0	0	2,789	0	730	1,217	463
Pacific	3,076	0	0	3,263,658	39,449	277,000	36,282	14,285
California	0	0	0	3,261,024	22,491	277,000	14,134	12,645
Oregon	0	0	0	542	0	0	20,422	1,641
Washington	3,076	0	0	2,092	16,958	0	1,726	0
Alaska	444	0	0	232	0	0	24,002	15,883
Hawaii	0	0	0	330,158	0	0	10,260	0

Table 153. INDUSTRIAL FUEL CONSUMPTION BY STATE

	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Lignite 10^3 tons/yr	Residual oil 10^3 gal/yr	Distillate oil[a] 10^3 gal/yr	Gas[a] 10^6 ft^3/yr	Bagasse 10^3 tons/yr	Wood 10^3 tons/yr
U.S. total	62,928	364	2,866	8,443,281	3,024,840	8,875,600	4,319	28,645
New England	141	6.0	0	1,090,110	119,196	64,800	0	1,376
Connecticut	49		0	305,718	41,538	19,000	0	0
Maine	8	1	0	317,310	15,960	4,500	0	1,293
Massachusetts	61		0	336,672	46,998	27,500	0	3
New Hampshire	8	2	0	60,942	5,166	4,500	0	24
Rhode Island	8		0	52,458	6,132	4,800	0	0
Vermont	7	3	0	17,010	3,402	4,500	0	51
Middle Atlantic	8068	342	0	1,847,832	369,936	562,400	9	154
New Jersey	78	121	0	638,400	113,736	82,700	9	0
New York	2318	1	0	427,476	111,216	127,800	0	0
Pennsylvania	5672	220	0	781,956	144,984	351,900	0	154
East North Central	27429	8.778	0	1,336,440	580,860	1,669,900	0	472
Illinois	4261	0	0	506,478	100,842	431,500	0	1
Indiana	5253	0	0	467,124	107,940	289,300	0	48
Michigan	5954	0	0	136,962	108,654	338,900	0	0
Ohio	9346	7.000	0	184,968	240,324	438,800	0	9
Wisconsin	2615	1.778	0	40,908	23,100	171,400	0	414
West North Central	5323	1.222	800	356,076	173,166	629,900	0	106
Iowa	1459	0	0	5,250	36,078	134,100	0	0
Kansas	414	0	0	62,622	17,598	175,500	0	0
Minnesota	970	1.222	0	205,044	36,498	119,300	0	87
Missouri	1424	0	0	51,492	54,432	120,600	0	15
Nebraska	414	0	0	4,074	18,774	72,300	0	0
North Dakota	321	0	800	24,738	3,864	2,000	0	0
South Dakota	321	0	0	2,856	5,922	6,100	0	4

[a] External and internal combustion combined.

Table 153 (continued). INDUSTRIAL FUEL CONSUMPTION BY STATE

	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Lignite 10^3 tons/yr	Residual oil 10^3 gal/yr	Distillate oil 10^3 gal/yr	Gas 10^6 ft^3/yr	Bagasse 10^3 tons/yr	Wood 10^3 tons/yr
South Atlantic	12,311	5.000	0	1,941,954	477,834	733,000	740	8,288
Delaware	925	3.000	0	154,182	10,584	10,200	0	0
District of Columbia	259	0	0	2,940	1,134	61,700	0	0
Florida	388	0	0	359,352	65,436	97,000	740	2,084
Georgia	388	0	0	305,172	67,284	175,100	0	2,286
Maryland	925	0	0	305,298	69,384	61,700	0	0
North Carolina	1,440	1.111	0	292,068	103,152	98,100	0	2,615
South Carolina	1,106	0.889	0	165,144	50,442	87,700	0	677
Virginia	2,516	0	0	341,628	80,684	54,900	0	626
West Virginia	4,364	0	0	16,170	29,734	86,600	0	0
East South Central	6,278	0	0	196,812	205,086	537,100	0	2,821
Alabama	2,311	0	0	92,988	60,060	161,200	0	872
Kentucky	1,868	0	0	31,878	42,924	77,500	0	68
Mississippi	0	0	0	58,968	30,492	137,800	0	1,264
Tennessee	2,099	0	0	12,978	71,610	160,600	0	597
West South Central	252	0	2,000	473,088	363,678	3,462,000	470	4,058
Arkansas	40	0	0	79,254	28,644	180,200	2	2,111
Louisiana	30	0	0	99,582	102,312	1,103,100	468	1,624
Oklahoma	32	0	0	53,508	55,440	141,900	0	0
Texas	150	0	2,000	240,744	177,282	2,036,800	0	323
Mountain	2,418	0	66	290,157	313,698	374,400	0	1,800
Arizona	137	0	0	106,302	10,122	65,900	0	0
Colorado	536	0	0	19,572	38,724	87,700	0	2
Idaho	295	0	66	1,365	30,996	-	0	1,166
Montana	295	0	0	37,800	56,910	38,700	0	632
Nevada	137	0	0	18,774	1,680	10,600	0	0
New Mexico	16	0	0	34,482	21,924	61,200	0	0
Utah	754	0	0	47,418	113,862	58,400	0	0
Wyoming	246	0	0	24,444	39,480	51,900	0	0
Pacific	245	1.333	0	839,412	398,454	842,100	0	9,466
California	13	0	0	502,362	246,582	660,000	0	1,359
Oregon		0	0	115,458	72,618	60,100	0	4,336
Washington	232	1.333	0	221,592	79,254	122,000	0	3,771
Alaska	463	0	0	22,764	11,970	15,200	0	104
Hawaii	0	0	0	48,636	10,962	230	3,100	0

Table 154. COMMERCIAL/INSTITUTIONAL FUEL CONSUMPTION BY STATE

	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Residual oil 10^3 gal/yr	Distillate oil 10^3 gal/yr	Gas 10^6 ft^3/yr	Wood 10^3 tons/yr
U.S. total	4,519	2,118	8,256,360	7,964,796	1,897,000	137
New England	47	2.9	2,009,112	1,220,646	45,000	0
Connecticut	14	0	241,248	88,494	11,000	0
Maine	0.75	0	158,340	72,928	1,000	0
Massachusetts	30	0.6	1,315,146	837,858	26,900	0
New Hampshire	0.75	0	80,682	70,434	1,900	0
Rhode Island	0.75	0	194,208	89,796	3,200	0
Vermont	0.75	2.3	19,488	59,136	1,000	0
Middle Atlantic	737	2,088	3,927,378	1,423,044	217,700	0
New Jersey	59	111	684,978	725,886	41,800	0
New York	21	229	2,531,508	254,100	97,200	0
Pennsylvania	657	1,748	710,892	443,058	78,700	0
East North Central	2,046	0	694,218	1,961,904	509,400	5.6
Illinois	245	0	420,672	525,630	147,900	0
Indiana	284	0	162,330	358,680	58,300	0
Michigan	349	0	53,466	603,540	125,700	0
Ohio	789	0	29,484	320,166	134,800	0
Wisconsin	379	0	28,266	153,888	42,700	5.6
West North Central	343	0	131,124	437,724	275,200	61.8
Iowa	35	0	12,726	39,312	51,300	0
Kansas	8	0	6,594	41,454	40,100	0
Minnesota	198	0	33,138	111,846	64,200	61.8
Missouri	56	0	55,650	169,218	70,400	0
Nebraska	5	0	10,164	75,894	30,500	0
North Dakota	20	0	12,726	0	8,700	0
South Dakota	21	0	126	0	10,000	0

Table 154 (continued). COMMERCIAL/INSTITUTIONAL FUEL CONSUMPTION BY STATE

	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Residual oil 10^3 gal/yr	Distillate oil 10^3 gal/yr	Gas 10^6 ft^3/yr	Wood 10^3 tons/yr
South Atlantic	581	21	872,046	867,636	170,300	0
Delaware	6	11	44,772	51,282	2,400	0
District of Columbia	4	0	213,234	35,028	3,200	0
Florida	13	0	106,890	125,496	26,800	0
Georgia	14	0	104,664	84,420	35,800	0
Maryland	26	10	221,676	138,432	26,500	0
North Carolina	238	0	83,874	204,246	18,500	0
South Carolina	160	0	8,400	38,976	13,100	0
Virginia	120	0	71,442	181,440	26,600	0
West Virginia	0	0	17,094	8,316	17,400	0
East South Central	585	0	60,984	484,428	119,100	6.4
Alabama	40	0	40,866	128,604	28,300	0
Kentucky	0	0	8,862	83,958	34,700	2.5
Mississippi	31	0	2,772	109,158	21,400	3.9
Tennessee	514	0	8,484	162,708	34,700	0
West South Central	0	0	73,122	807,744	221,800	0
Arkansas	0	0	19,614	80,724	31,000	0
Louisiana	0	0	630	99,540	41,500	0
Oklahoma	0	0	4,410	86,352	32,900	0
Texas	0	0	48,468	541,128	116,400	0
Mountain	180	0	84,336	347,508	139,600	0
Arizona	0.62	0	0	34,230	22,300	0
Colorado	112	0	25,662	70,938	51,000	0
Idaho	37	0	6,930	27,426	7,400	0
Montana	30	0	8,736	17,472	13,900	0
Nevada	0.29	0	3,402	8,904	9,500	0
New Mexico	0	0	2,814	66,360	18,800	0
Utah	0	0	23,436	80,388	6,300	0
Wyoming	0	0	13,356	41,790	10,000	0
Pacific	0	0	399,966	414,162	190,400	63.4
California	0	0	133,098	408,114	157,800	0
Oregon	0	0	138,852	6,048	10,000	63.4
Washington	0	0	128,016	0	221,000	0
Alaska	0	0	546	0	8,400	0
Hawaii	0	0	3,528	0	0	0

Table 155. RESIDENTIAL FUEL CONSUMPTION BY STATE

	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Lignite 10^3 tons/yr	Distillate oil 10^3 gal/yr	Gas 10^6 ft^3/yr	Wood 10^3 tons/yr
U.S. total	5,189	2,904	100	16,244,690	5,371,472	4,875
New England	13.18	55.6	0	2,993,390	131,111	155
Connecticut	9	6.3	0	713,790	32,872	9
Maine	0.5	8.3	0	375,280	3,723	80
Massachusetts	2.71	26.9	0	1,300,120	87.371	13
New Hampshire	0.32	3.5	0	240,490	2,360	25
Rhode Island	0.45	1.3	0	213,140	3,294	0.3
Vermont	0.20	9.3	0	150,570	1,491	25
Middle Atlantic	0	2211.7	0	6,012,720	793,322	127
New Jersey	0	41.4	0	1,048,880	139,673	8
New York	0	435.3	0	3,676,150	353,845	67
Pennsylvania	0	1735.0	0	1,287,690	299,804	52
East North Central	1413.4	340.6	0	2,878,260	1,602,710	279
Illinois	689.3	64.0	0	541,660	476,975	28
Indiana	165.6	40.9	0	445,780	178,511	57
Michigan	212.1	100.0	0	693,230	360,730	61
Ohio	267.2	127.9	0	480,730	455,844	45
Wisconsin	79.2	7.8	0	711,860	130,650	88
West North Central	208	10.6	100	1,288,170	622,483	502
Iowa	9.2	0	0	278,830	112,965	16
Kansas	8.1	0	0	10,220	112,068	25
Minnesota	49.2	10.6	0	623,680	125,168	98
Missouri	135.4	0	0	118,800	184,513	327
Nebraska	6.1	0	0	54,110	60,455	12
North Dakota	0	0	100	143,460	10,886	3
South Dakota	0	0	0	109,070	16,428	21

Table 155 (continued). RESIDENTIAL FUEL CONSUMPTION BY STATE

	Bituminous 10^3 tons/yr	Anthracite 10^3 tons/yr	Lignite 10^3 tons/yr	Distillate oil 10^3 gal/yr	Gas 10^6 ft^3/yr	Wood 10^3 tons/yr
South Atlantic	851.7	103.2	0	2,018,480	407,427	1,380
Delaware	0	5.4	0	90,160	8,828	6
District of Columbia	20.5	0	0	69,530	0	1
Florida	24.7	0	0	115,510	29,863	39
Georgia	20.0	0	0	37,860	99,708	350
Maryland	0	25.4	0	438,030	91,038	49
North Carolina	143.3	0	0	566,310	36,309	350
South Carolina	69.9	0	0	186,410	28,443	247
Virginia	330.3	8.8	0	472,990	56,442	300
West Virginia	243.0	63.6	0	41,680	56,796	38
East South Central	1450.5	132.8	0	131,690	268,281	994
Alabama	11.6	0	0	9,860	72,205	270
Kentucky	314.0	132.8	0	1,620	93,863	198
Mississippi	7.7	0	0	73,920	49,158	200
Tennessee	1117.2	0	0	46,290	53,055	326
West South Central	883.1	17.6	0	10,120	555,609	469
Arkansas	90.6	1.8	0	2,450	2,450	287
Louisiana	170.0	3.4	0	1,470	104,016	40
Oklahoma	120.0	2.4	0	1,270	92,363	81
Texas	502.5	10.0	0	4,930	289,943	88
Mountain	337.6	11.1	0	208,300	290,867	337.7
Arizona	.074	0	0	2,350	38,579	66.8
Colorado	56.5	0	0	11,640	109,222	14.7
Idaho	72.	0	0	99,770	12,193	58.3
Montana	72.	0	0	43,310	27,773	56.4
Nevada	.016	0	0	27,420	10,325	12.9
New Mexico	0	4.7	0	3,140	24,491	109.6
Utah	187.	0	0	16,000	51,588	10.
Wymong	22.	6.4	0	4,670	16,696	9.
Pacific	32.	20.4	0	703,560	694,331	604.
California	0	0	0	18,110	631.354	168.0
Oregon	20.	0	0	225,730	24,471	263.1
Washington	12.	20.4	0	459,720	38,506	173.0
Alaska	0	0	0	0	5,331	0
Hawaii	0	0	0	0	0	0

APPENDIX C

TRACE ELEMENT CONTENT OF ASH COLLECTED BY USE CATEGORY (TONS/YEAR) AND OF FUELS

The trace element content of ash collected in the utility, industrial, commercial/institutional and residential sectors is presented in Tables 156 through 159. These tables, in conjunction with the state fuel consumption figures in Appendix B, can be used to estimate the trace element content of the solid waste contribution of specific combustion systems. Table 160 presents the trace element content (ppm) of the various fuels. These values have been used as the basis for the emission estimates presented in the text and for the derivation of Table 156 through 159.

Table 156. ELECTRIC GENERATION: ASH TRACE ELEMENTS[a]

	Bituminous	Anthracite	Lignite
Sb	138	0.11	
As	12,000	10.9	
Ba	11,500	72	3,100
Be	670	3.3	2.1
Bi	279	0.11	15
B	14,800	1.1	380
Br	0	0	0
Cd	99	1.0	
Cl	0	0	0
Cr	4,000	131	38
Co	1,300	118	50
Cu	3,500	83	77
F	0	0	0
Fe	1,200,000	8,900	
Pb	2,200	8.4	51
Mn	13,000	15.3	520
Hg	5	0.4	
Mo	1,000	11	14.5
Ni	4,100	55	26
Se	310	0.1	
Te	83	0.11	
Tl	28	0.11	
Sn	265	1.1	27
Ti	163,000	650	
U	4,200	0.4	
V	7,700	13	75
Zn	6,100	36	140
Zr	15,300	63	900

[a] Tons bottom ash and collected fly ash, 1974.

Table 157. INDUSTRIAL: ASH TRACE ELEMENTS[a]

	Bituminous	Anthracite	Lignite
Sb	28	0.025	
As	1,200	3.6	
Ba	1,600	18	710
Be	100	0.94	0.51
Bi	42	0.025	4.4
B	2,200	0.28	96
Br	0	0	0
Cd	17	0.028	
Cl	0	0	0
Cr	600	37	9.6
Co	150	28	9.8
Cu	530	23	19
F	0	0	0
Fe	130,000	2,100	
Pb	390	2.7	15
Mn	150	4.3	9.0
Hg	1.4	0.001	
Mo	160	3.6	3.6
Ni	600	15	6.4
Se	90	0.022	
Te	13	0.028	
Tl	4.2	0.028	
Sn	41	0.28	6.9
Ti	25,000	190	
U	640	0.076	
V	1,200	4.0	20
Zn	930	10	30
Zr	1,900	15	190

[a] Tons, 1973, bottom ash and collected fly ash.

Table 158. COMMERCIAL: ASH TRACE ELEMENTS[a]

	Bituminous	Anthracite
Sb	1.9	0.21
As	100	20
Ba	130	120
Be	8.5	6.0
Bi	2.6	0.21
B	140	2.1
Br	0	0
Cd	1.5	0.21
Cl	0	0
Cr	62	240
Co	13	160
Cu	45	150
F	0	0
Fe	12,400	14,000
Pb	32	18
Mn	60	28
Hg	0.069	0.058
Mo	13	20
Ni	52	100
Se	3.8	0.13
Te	1.0	0.21
Tl	0.35	0.21
Sn	3.4	2.1
Ti	2,140	1,200
U	54	0.54
V	99	26
Zn	77	63
Zr	161	96

[a] Tons 1973, bottom ash.

Table 159. RESIDENTIAL: ASH TRACE ELEMENTS[a]

	Bituminous	Anthracite	Lignite	Distillate
Sb	2.5	0.3		2.4
As	166	30	0	
Ba	190	172	30	
Be	12	9	0.02	
Bi	5	0.3	0.2	
B	273	3	5	
Br	0	0	0	0
Cd	2	0.3	0	
Cl	0	0	0	0
Cr	74	359	0.5	
Co	19.6	270	0.44	
Cu	65	224	0.82	1.6
F	0	0	0	0
Fe	18,000	20,000		
Pb	46	27	0.6	
Mn	18	42	0.4	0.36
Hg	0.007	0	0	
Mo	19	30	0.15	
Ni	74	148	0.3	
Se	4	0.2		
Te	1.6	0.3		
Tl	0.5	0.3		
Sn	5	3	0.3	30
Ti	3,000	1,790		
U	77	0.8		
V	143	39	0.9	
Zn	112	98	1.2	
Zr	240	143	8	

[a] Tons bottom ash.

Table 160. TRACE ELEMENTS IN FUEL, ppm

	Bituminous	Anthracite	Lignite	Residual	Distillate
Sb	0.5	0.10		0.04	
As	28.0	10.00		0.30	0.04
Ba	36.0	58.00	303.0	0.67	
Be	2.0	3.00	0.2	0.09	
Bi	1.0	0.10	1.6		
B	53.0	1.00	41.0	0.11	
Br	15.0	1.00	0.1	0.17	0.01
Cd	0.4	0.10		2.02	
Cl	1500.0	1500.00	2000.0	16.23	
Cr	14.0	120.00	4.1	1.78	
Co	4.0	90.00	4.0	2.24	
Cu	13.0	75.00	8.0	10.00	0.03
F	81.0	110.00			
Fe	3500.0	6800.00		7.25	
Pb	9.0	9.00	6.0	0.04	
Mn	46.0	182.00	31.0	2.08	0.13
Hg	0.2	0.30		0.02	
Mo	4.0	10.00	2.0	2.30	
Ni	14.0	50.00	3.0	50.07	
Se	3.0	0.20		0.14	
Te	0.3	0.10			
Tl	0.1	0.10			
Sn	1.0	1.00	5.0		0.49
Ti	589.0	600.00		5.41	
U	15.0	0.30		1.40	
V	28.0	13.00	9.0	57.14	
Zn	22.0	33.00	12.0	0.19	
Zr	47.0	48.00	80.0		

APPENDIX D

AIR AND WATER QUALITY STANDARDS

AIR POLLUTANTS

Standards

Certain contaminants have been classified by law as pollutants and for which maximum allowed ambient levels have been established by the U.S. Environmental Protection Agency. Table 161 contains a list of these ambient air standards.[1]

Ambient air quality standards are to be achieved by regulatory activities as specified in state implementation plans (SIP's) and approved by the U.S. Environmental Protection Agency. The SIP's contain emission standards for various types of emission sources and pollutants. In addition, the Federal government has promulgated new source performance standards for important classes of emission sources such as coal burning boilers, petroleum refineries and incinerators. The NSPS promulgated for stationary fossil fuel boilers by the EPA are exemplified in Table 162. State emission standards for several western states, some of which are stricter than the Federal standards, are presented in Table 163.

WATER POLLUTANTS

Standards

The EPA has published proposed criteria for water quality for various types of aquatic environments. These criteria,[3] which are listed in

Table 161. AMBIENT AIR STANDARDS[a]

Species	Averaging period[f]	Air quality standards[b]		Episode levels[c]			Industrial health[d,e]
		Primary	Secondary	Alert	Warning	Emergency	TLV
SO_x (as SO_2)	AAM	80(0.03)	60(0.02)				
	24	365(0.14), 1x	260(0.09), 1x	800(0.30)	1,000(0.38)	2,100(0.79)	
	8						13,000(4.9)
	3		1,300(0.49), 1x				
Particulate	AGM	75	60[h]				
	24	260, 1x	150, 1x	375	750	1,000	
	8						-(15)
Carbon monoxide	8	10,000(9), 1x	10,000(9), 1x	17,000(15)	34,000(30)	46,000(40)	55,000(47)
	1	40,000(35), 1x	40,000(35), 1x				
Oxidant (as O_3)	8						200(0.1)[j]
	1	160(0.08), 1x	160(0.08), 1x	200(0.1)	800(0.4)	1,200(0.6)	
NO_x (as NO_2)	AAM	100(0.05)[i]	100(0.05)[i]				
	24			282(0.15)	565(0.3)	750(0.4)	
	8						9,000(4.7)
	1			1,130(0.6)	2,260(1.2)	3,000(1.6)	
Nonmethane	8						-(16)
Hydrocarbons (as CH_4)	3[m]	160(0.24), 1x	160(0.24), 1x				

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[a] Format for each entry is as follows: STANDARD $\mu g/m^3$ @ 760 mmHg & 20°C (Equivalent Value, ppm). The maximum allowable exceedance rate, if any, follows. This refers to the maximum number of times per year that the standard may be exceeded. For example, 1x means the standard may be exceeded only once per year.

[b] "National Primary and Secondary Ambient Air Quality Standards," Federal Register 36, No. 84, pp 8186-8201.

[c] "Requirements for Preparation, Adoption and Submittal of Implementation Plans," Federal Register, 35, No. 158, pp 15486-15502.

[d] "Occupational Safety and Health Standards, National Concensus Standards and Established Federal Standards," Federal Register, 35, No. 105, pp 10466-10714.

[e] "Occupational Safety and Health Standards - Miscellaneous Amendments," Federal Register, 36, No. 157, pp 15101-15107.

[f] **The averaging period is given in hours unless otherwise specified. AAM means Annual Arithmetic Mean Value and AGM means Annual Geometric Mean Value.**

Table 162. PROMULGATED NEW SOURCE PERFORMANCE STANDARDS — POWER PLANTS

Source category and pollutant Fossil-fuel-fired steam generating with >63 x 10^6 keal/hr (250 x 10^6 Btu/hr) of heat input	New source performance standard (maximum 2-hr average)
Coal-burning plants	
Particulates	0.18 g/10^6 cal heat input (0.10 lb/10^6 Btu)
Sulfur dioxide	2.2 g/10^6 cal heat input (1.2 lb/10^6 Btu)
Nitrogen oxides (as NO_2)[a]	1.26 g/10^6 cal heat input (0.70 lb/10^6 Btu)
Oil-burning plants	
Particulates	0.18 g/10^6 cal heat input (0.10 lb/10^6 Btu)
Sulfur dioxide	1.4 g/10^6 cal heat input (0.80 lb/10^6 Btu)
Nitrogen oxides (as NO_2)	0.54 g/10^6 cal heat input (0.30 lb/10^6 Btu)
Gas-burning plants	
Particulates	0.18 g/10^6 cal heat input (0.10 lb/10^6 Btu)
Nitrogen oxides (as NO_2)	0.36 g/10^6 cal heat input (0.20 lb/10^6 Btu)

[a] At this time there is no NSPS for NO_x emissions from lignite-fired steam generators.

Table 163. EMISSION STANDARDS FOR NEW COAL-FIRED POWER PLANT IN THE WESTERN UNITED STATES[2,a]

State	SO_2 lb/10^6 Btu	Particulate lb/10^6 Btu	NO_x lb/10^6 Btu
	Federal standards		
	1.2	0.10	0.70[f]
	State standards		
New Mexico	0.34	0.15[b]	0.45
Nevada	0.40	0.13	- [c]
Arizona	0.80	0.13	0.70
Montana	1.00	0.14	- [c]
Missouri	1.17	0.10[b]	- [c]
Arkansas	1.20	0.10	0.70
Oklahoma	1.20	0.12	0.70
Oregon	1.20	0.20	- [c]
South Dakota	1.20	0.10	0.70
Colorado	1.28[d]	0.10	0.70
Minnesota	1.75	0.40	- [c]
Washington	2.33	0.20	- [c]
Nebraska	2.50	0.15[b]	0.67
Idaho	2.78	0.14	- [c]
Kansas	3.00	0.14[b]	0.90
North Dakota	3.00	0.27[b]	- [c]
Texas	3.00	0.30	- [c]
Iowa	6.00[b]	0.60	- [c]
Wyoming	- [e]	0.10[b]	0.70
California	No statewide standards, local standards vary		
Utah	No standards		

[a] Standards given are those in effect in May 1975. Where plant size affects the emission standard, values are based on 500 MW. All standards have been converted to units of lb/10^6 Btu. Conversions from gr/dscf, where performed, were based on combustion of coal having a moisture-free analysis of 65 pct carbon and 10,600 Btu/lb, burned with 30 pct excess air. County standards are not included in this table.

[b] The units presented in the regulation are "lb/hr/MM Btu."

[c] Indicates there are no statewide standards.

[d] Effective January 1, 1980, SO_2 is restricted to 0.35 lb/MM Btu.

[e] The current Wyoming SO_2 emission standard applied to sulfuric acid plants. There is no current standard for power plants.

[f] The Federal Standard for NO_x does not apply to lignite.

Table 164, includes not only chemical pollutants but also bilogical contaminants, heat (temperature limits) and other pollutant forms. Effluent standards for many source classes have been proposed and are promulgated by the U.S. EPA. Proposed effluent standards for steam electric power generating point sources have been published (see Section E of this Appendix).[4]

Organic Pollutants

Organic pollutants are particularly troublesome because of their high activity with other water stream contaminants. A prime example of this type of interaction is the large concentration of possibly carcinogenic chlorohydrocarbons recently found in the New Orleans drinking water supply.[5] This situation was brought about by the chlorination of processed industrial water containing significant concentrations of hydrocarbons. Thus, the presumably beneficial effect of chlorine addition to the drinking water supply may have been negated by its subsequent reaction with the low level contaminant.

Various organisms are able to methylate mercury by oxidizing the elemental metal to its divalent state from which it reacts with naturally occurring hydrocarbons to form methyl mercury. Similar reactions also occur with elements such as cadmium and selenium.[1]

SOLID WASTE POLLUTANTS

Of the three pollutant media, air, water and solid, the emissions and effects of emissions in the solid state are least understood. In fact, the delineation between solid effluents and solid contaminants remains a gray area. One is often faced with the vexing question - Does solid waste used as landfill constitute pollution and, if so, at what stage? In general, a solid waste pile can be considered neutral (other than as perhaps an eyesore) with respect to the ambient environment until the

Table 164. TABULAR SUMMARY OF WATER QUALITY CRITERIA[3]

Constituent	Agriculture (irrigation)	Agriculture (livestock)	Freshwater (aquatic life)	Freshwater (wildlife)	Freshwater (public supply)	Marine water (aquatic life)	Recreational waters
pH	4.5-9.0	--	6.0-9.0	6.0-9.0	5.0-9.0	6.5-8.5	Acceptable - 6.5-8.3 Must be - 5.0 - 9.0
Alkalinity	--	--	75% natural level	30-130 mg/l	No limit[a]	--	--
Acidity	--	--	Addition of acids unacceptable	--	No limit	--	--
BOD	No limit	--	--	--	--	--	--
Al	5.0 mg/l 20.0 mg/l (20 yrs)	5.0 mg/l	--	--	--	1/100 (0.01) 96-hr LC_{50} 1.5 mg/l 1/10 LD_{50}	--
NH_3	--	--	1/20 (0.05) LC_{50} 0.02 mg/l	--	0.5 mg/l	0.4 mg/l	--
Sb	--	--	--	--	--	1/50 (0.02)[b] 96-hr LC_{50} 0.2 mg/l	--
As	0.10 mg/l 2.0 mg/l (20 yrs)	0.2 mg/l	--	--	0.1 mg/l	1/100 (0.01) 96-hr LC_{50} 0.05 mg/l	--
Ba	--	--	--	--	1.0 mg/l	1/20 (0.05) LD_{50} 1.0 mg/l	--
Be	0.1 mg/l 0.5 mg/l (20 yrs)	No limit	--	--	--	1/100 (0.01) 96-hr LC_{50} 1.5 mg/l	
Bi	--	--	--	--	--	No limit	--
B	0.75 mg/l Sen. 1.0 mg/l Semi-Tol. 2.0 mg/l Tol.	5.0 mg/l	--	--	1.0 mg/l	1/10 (0.1) 96-hr LC_{50}	
Br	--	--	--	--	--	0.1 mg/l (free) 100 mg/l (ionic)	--

Table 164 (continued). TABULAR SUMMARY OF WATER QUALITY CRITERIA[3]

Constituent	Agriculture (irrigation)	Agriculture (livestock)	Freshwater (aquatic life)	Freshwater (wildlife)	Freshwater (public supply)	Marine water (aquatic life)	Recreational waters
HCO_3	No limit	--	--	--	--	--	--
Cd	0.01 mg/l 0.05 mg/l (20 yrs)	50 μg/l	0.03 mg/l hard H_2O 0.004 mg/l soft H_2O	--	0.01 mg/l	1/100 (0.01)[c] 96-hr LC_{50} 0.01 mg/l	--
Cl (free)	No limit	--	0.003 mg/l 0.05 mg/l (30 min)	--	--	1/10 (0.1) 96-hr LC_{50} 0.01 mg/l	--
Cl_2 (Chloride)	No limit	--	--	--	250 mg/l	--	--
Cr	0.1 mg/l 1.0 mg/l (20 yrs)	1.0 mg/l	0.03 mg/l	--	0.05 mg/l	1/100 (0.01) 96-hr LC_{50} 0.1 mg/l	--
CO	0.05 mg/l 5.0 mg/l (20 yrs)	1.0 mg/l	--	--	--	--	--
Cu	0.20 mg/l 5.0 mg/l	0.5 mg/l	1/10 (0.1) 96-hr LC_{50}	--	1 mg/l	1/100 (0.01) 96-hr LC_{50} 0.05 mg/l	--
(CN)	--	--	1/20 (0.05) 96-hr LC_{50}	--	0.2 mg/l	1/10 (0.1) 96-hr LC_{50} 0.01 mg/l	--
F	2.0 mg/l 1.0 mg/l (Sandy soil) 15.0 mg/l (20 yrs)	2.0 mg/l	--	--	--	1/10 (0.1) 96-hr LC_{50} 1.5 mg/l	--
H_2S	--	--	See sulfides	--	--	1/10 (0.1) 96-hr LC_{50} 0.01 mg/l	--
Fe	5.0 mg/l 20.0 mg/l (20 yrs)	No limit	--	--	0.3 mg/l	0.3 mg/l	--
Pb	5.0 10.0 mg/l	0.1 mg/l	0.03 mg/l	--	0.05 mg/l	1/50 (0.20 96-hr LC_{50} 0.01 LD_{50}	--
Li	2.5 mg/l 0.075 mg/l	--	--	--	--	0.01 LD_{50} 24-hr max 0.05 mg/l	--

Table 164 (continued). TABULAR SUMMARY OF WATER QUALITY CRITERIA[3]

Constituent	Agriculture (irrigation)	Agriculture (livestock)	Freshwater (aquatic life)	Freshwater (wildlife)	Freshwater (public supply)	Marine water (aquatic life)	Recreational waters
Mn	0.20 mg/l 10.0 mg/l (20 yrs)	No limit	--	--	0.05 mg/l	1/50 (0.20) 96-hr LC_{50} 0.01 mg/l	--
Hg Inorganic	--	1.0 µg/l	0.2 µg/l Tot. conc. 0.05 µg/l Avg. conc. 0.5 µg/g Body burden Conc. Total Hg	0.5 µg/g in fish	0.002 mg/l Total	1/100 (0.01)	--
Hg Organic	--	--	0.2 µg/l Tot. conc. 0.05 µg/l Avg. conc. 0.5 µg/g Body burden Conc. Totl. Hg	--	--	--	--
Mo	0.01 mg/l 0.05 mg/l	No limit	--	--	--	1/20 (0.05) 96-hr LC_{50}	--
Ni	0.2 mg/l 2.0 mg/l (20 yrs)	--	1/50 96-hr LC_{50}	--	--	1/50 (0.02) 96-hr LC_{50} 0.1 mg/l	--
(NO_3)	No limit	100 mg/l Combined (NO_3) & (NO_2)	--	--	10 mg/l	--	--
(NO_2)	--	10 mg/l	--	--	1 mg/l	--	--
P	--	--	--	--	No limit	1/100 (0.01) 96-hr LC_{50} 0.1 µg/l	25 µg/l Lakes & res. 50 µg/l At confluence 100 µg/l Streams
Se	0.02 mg/l	0.05 mg/l	--	--	0.01 mg/l	1/100 (0.01) 96-hr LC_{50} 0.01 mg/l	--
Na	No limit	--	--	--	No limit	--	--
Ag	--	--	--	--	0.05 mg/l	1/20 (0.50) 96-hr LC_{50} 5.0 µg/l	--

Table 164 (continued). TABULAR SUMMARY OF WATER QUALITY CRITERIA[3]

Constituent	Agriculture (irrigation)	Agriculture (livestock)	Freshwater (aquatic life)	Freshwater (wildlife)	Freshwater (public supply)	Marine water (aquatic life)	Recreational waters
Tl	--	--	--	--	--	1/20 (0.05) 96-hr LC_{50} 0.1 mg/1	--
U	--	--	--	--	--	1/100 (0.01) 96-hr. LC_{50} 0.5 mg/1	--
V	--	0.1 mg/1	--	--	--	1/20 (0.05) 96-hr LC_{50}	--
Zn	--	25 mg/1	3/1000 (0.003) 96-hr LC_{50}	--	5 mg/1	1/100 (0.01) 96-hr LC_{50} 0.1 mg/1	--
Viruses	--	--	--	--	No limit	--	--
Micro-Organisms	--	5000 coli-forms/100 ml[d] 20,000/100 ml[e]	--	2000/100 ml	10,000/100 ml	--	--
Fecal Coliforms	1000/100 ml	1000/100 ml[a] 4000/100 ml[b]	--	2000/100 ml	2000/100 ml	--	2000/100 ml avg. 4000/100 ml max. log mean 2n 200/100 ml <10% samples in 30 days to exceed 400/100 ml
Dissolved Solids (tot)	2000-5000 mg/1 (Tolerant) 500-1000 mg/1 (Sensitive)	--	Bioassays	--	No limit	--	--
Hardness	--	--	(See T.D.S.)	--	No limit	--	--
Suspended & Settleable Solids	No limit	--	80 mg/1	--	--	--	--
Temperature	No limit	--		(Minimized) maintain natural pattern	Not to detract from potability	2.0 (3.6F)9-5 1.0 (1.8F)6-8	86 F

Table 164 (continued). TABULAR SUMMARY OF WATER QUALITY CRITERIA[3]

Constituent	Agriculture (irrigation)	Agriculture (livestock)	Freshwater (aquatic life)	Freshwater (wildlife)	Freshwater (public supply)	Marine water (aquatic life)	Recreational waters
Toxic Algae	--	Heavy growth of blue-green not accepatble	--	No limit	--	--	--
Botulism	--	--	--	Minimizes factors which promote disease	--	--	--
Pesticides	--	See Public Water Stnds.	1/100 (0.01) 96-hr LC_{50} Those for which no toxicity data available	--	--	1/100 (0.01) 96-hr LC_{50}	--
Dalapon	0.2 μg/l	--	--	--	Silvex 0.03	--	--
TCA	0.2 μg/l	--	--	--	2,3,5-T 0.002	--	--
2,4-D	0.1 μg/l	--	--	--	0.02 μg/l	--	--
Insecticides	No limit	--	--	DDT 1 mg/kg wet weight	Organophosphates 0.1 mg/l	--	--
Turbidity	--	--	<10% change in C.P.	--	No limit	--	Clarity - 4 ft. Secchi
Carbon Adsorbable	--	--	--	--	0.3 mg/l CCE 1.5 CAE	--	--
Foaming Agents	--	--	--	--	0.5 mg/l (ABS)	--	--
NTA	--	--	--	--	No limit	--	--
Phenols	--	--	--	--	1 μg/l	--	--
Color	--	--	Comp. pt. not changed by >10%	--	75 platinum-cobalt units	--	--

Table 164 (continued). TABULAR SUMMARY OF WATER QUALITY CRITERIA[3]

Constituent	Agriculture (irrigation)	Agriculture (livestock)	Freshwater (aquatic life)	Freshwater (wildlife)	Freshwater (public supply)	Marine water (aquatic life)	Recreational waters
Radio-activity	See Federal Drinking Water Standards	See Federal Drinking Water Standards	See Federal Drinking Water Standards	--	See Federal Drinking Water Standards	See Federal Drinking Water Standards	--
Salinity	--	3000 mg soluble salts/l	--	No rapid fluctuation	--	--	--
D.O.	--	--	See Table Section V	--	No limit saturation preferred	6.0 mg/l	--
Sulfate	--	--	--	--	250 mg/l	--	--
Sulfides	--	--	0.002 mg/l	--	--	--	--
Detergents	--	--	1/20 (0.05) (LAS) 96-hr LC_{50} 0.2 mg/l max.	--	--	--	--
Oils	--	--	No visible oil 1/20 (0.05) 96-hr LD_{50} Hexane extractable sediments 1000 mg/kg	No visible floating oils	--	No film or odor No tainting of fish No onshore oil deposit	--
Phthalate Esters	--	--	0.3 μg/l	--	No limit	--	--
PCB's	--	--	0.002 μg/l (in water) 0.5 μg/g (in tissue)	No increase	No limit	--	--
Tainting Substances	--	--	Tables 3 & 4	--	--	--	--
Odor	--	--	--	--	Free	--	--
Light	--	--	--	<10% change in C.P.	--	--	--

[a] "No limit," where it appears in this table, refers to constituents that were addressed but for which it was indicated that insufficient data existed for prescribing limits.

[b] LC_{50} values are the concentration levels which if exceeded over the time period specified will prove fatal to 50 percent of fish.

[c] If cooper or zinc is present > 1 mg/l, then AF - 0.001 LC_{50}.

[d] Average of a minimum of 2 samples per month.

[e] Individual sample.

constituents of the waste pile interact with air, water (ground or surface) or soil. Since solid wastes are often placed in clay, asphalt, rubber or plastic liners, these cross media effects often have a long time lag before environmental degradation begins. Therefore, in assessing solid waste effects, factors such as liner breakage, diffusion rates through liners, evaporation rates, leaching rates, and runoff composition must be estimated in order to determine which solid effluents eventually appear in which media and at what rates. For these reasons there are no emission or ambient solid waste standards; however, effluents to air and water which are initially removed as solid waste must be taken into account in emissions to the former media.

Since solid samples are considerably more difficult to analyze chemically than air or water samples, solid waste piles are usually characterized by broad parameters such as pH, BOD, COD, anion content, bilogical parameters, etc. Leaching rates from solid waste piles determine the magnitude and type of solid and water pollution. Since leaching rates range from almost nothing to 100 feet per year depending upon soil type, runoff, ground water levels, and liner permeability, pollution problems associated with solid waste disposal may develop immediately or may have time lags of several years from plant start-up dates.

Ground and surface water pollution from sanitary landfills occurs through two different leaching processes. The first process is the dissolving of solid and liquid pollutants present in a landfill by excess water and their subsequent transportation out of the fill into surface or ground water reservoirs. The second process is the solution of CO_2 produced by bacterial action on organic compounds, in the ground water adjacent to the fill, and the consequent solution of minerals, mainly carbonates and bicarbonates, resulting in excessive alkalinity and hardness of the ground water.

OTHER POLLUTANTS

Thermal Water Pollution[7,8]

Introduction - A power plant can release heat into the environment in several ways. Some of the heat generated during fossil fuel combustion will escape through stacks. An even greater amount is lost to cooling water used in condensers. The amount of heat rejected to cooling water represents about 45 percent of the heating value of fossil fuels used in the most efficient plants. Overall, more than 80 percent of all thermal water pollution in the United States comes from electricity generating plants.[9] It has been predicted[10] that by the year 2000 the electric power industry will require four times as much cooling as was needed in 1965, thereby presenting a potential fourfold increase in thermal water pollution. In the cooling process heat can be released directly to a nearby body of water or indirectly via water droplets evaporated from a cooling tower.

Effects[11,12] of Thermal Pollution

The deleterious effects of higher than ambient water temperature are:

(a) Decreased dissolved oxygen content;

(b) Increased reaction rates between primary contaminants which yield secondary pollutants;

(c) Lethal or harmful effects on fish and other aquatic organisms;

(d) Harboring of pathogenic disease causing organism;

(e) Decrease in attractiveness of recreational waters;

(f) Adverse effects on adjoining land ecology;

(g) Decreased crop growth and yields due to decreased effectiveness of irrigation water;

(h) Decreased ability of surface waters to self-purify.

The last effect is a direct result of (a) since dissolved oxygen is necessary to oxidize organic pollutants. An example[7] of harmful effects upon aquatic organisms is the rate of shell growth of the clam *Mercenaria mercenaria* as a function of temperature which peaks at 20°C and falls off symmetrically with a half width at 12°C.

Standards - Since surface water temperatures vary widely with geographical location and climate, no fixed criteria for ambient temperatures can be set. However, standard regulating thermal discharges have been proposed.[4] The following conditions are considered to detract from water quality:[11]

- Water temperature higher than 85°F (29.4°C);
- More than 5°F water temperature increase in excess of that caused by ambient conditions;
- More than 1°F hourly temperature variation over that caused by ambient conditions;
- Any water temperature change which adversely affects the biota, taste, odor, or the chemistry of the water:
- Any water temperature variation or change which adversely affects water treatment plant operation (e.g., speed of chemical reactions, sedimentation basin hydraulics, filter wash requirements, etc.);
- Any water temperature change that decreases the acceptance of the water for cooling and drinking purposes;
- Any irrigation water temperature which significantly influences soil temperature.

Cooling Tower Plumes - As a result of the National Environmental Policy Act of 1969, once-through cooling systems have begun to be replaced by several alternative heat removal techniques. Among these alternatives are cooling towers which are basically air-water heat exchangers which allow for the transfer of much of the cooling water heat content to ambient air. One of the principal environmental disadvantages of cooling towers, particularly the more common wet variety, is the formation of visible plumes of water droplets.

The more serious visible pollution associated with plume formation are ground level fog, icing, snow formation and salt deposition. These effects, as well as the extent of the plume, are functions of ambient temperature, wind conditions, water droplet composition, cooling tower emission rate, and relative humidity.

A frequently invoked, yet incorrect, criteria for plume visibility is the attainment of 100 percent relative humidity. In fact, three processes lengthen the visible part of the plume: nonuniform distribution of water vapor droplets in the plume, finite droplet evaporation time and droplet vapor pressure lowering due to dissolved condensation nuclei.

Visible pollution resulting from plume formation is generally quite localized and becomes problematic only in certain situations, such as low level fogging of a highway or interference with airplane navigation. Natural fog formation is generally more common and more severe.

Noise

Noise can be defined as unwanted sound or sound without intrinsic value. In general, the higher the noise level the larger the disturbance and the more intermittent, the greater the annoyance. Some of the complex effects of noise pollution, considered important by the EPA, are:[13]

- Hearing damage;
- Other health effects such as alteration of the function of the endocrine, cardiovascular, and nervous system;
- Behavioral effects such as interference with concentration ability;
- Sleep interference;
- Communication interference;
- Effects on animals;

While there are no federal regulations proposed for ambient noise levels, the EPA has identified noise levels,[14] which, if exceeded, may be deleterious to the public health and welfare.

EFFLUENT GUIDELINES AND STANDARDS FOR STEAM ELECTRIC POWER GENERATING

ENVIRONMENTAL PROTECTION AGENCY
EFFLUENT GUIDELINES AND STANDARDS FOR STEAM ELECTRIC POWER GENERATING

40 CFR 423; 39 FR 36186, October 8, 1974, Effective November 7, 1974; 40 FR 7095, February 19, 1975; 40 FR 23987, June 4, 1975)

Title 40—Protection of the Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

[FRL 274-5]

SUBCHAPTER N—EFFLUENT GUIDELINES AND STANDARDS

PART 423—STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

AUTHORITY: Secs. 301, 304 (b) and (c), 306 (b) and (c), 307(c) and 501(a) of the Federal Water Pollution Control Act, as amended (33 U.S.C. 1215, 1311, 1314 (b) and (c), 1316 (b) and (c), 1317(c) and 1361(a)), 86 Stat. 816 et seq.; Pub. L. 92-500

Subpart A—Generating Unit Subcategory

§ 423.10 Applicability; description of the generating unit subcategory.

The provisions of this subpart are applicable to discharges resulting from the operation of a generating unit by an establishment primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam-water system as the thermodynamic medium.

§ 423.11 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided below, the general definitions, abbreviations and methods of analysis set forth in 40 CFR Part 401 shall apply to this subpart.

(b) The term "generating unit" shall mean any generating unit subject to the provisions of this part, except those units defined below as small, or old.

(c) The term "small unit" shall mean any generating unit subject to the provisions of this part, except a unit defined below as old, of less than 25 megawatts rated net generating capacity or any unit which is part of an electric utilities system with a total net generating capacity of less than 150 megawatts.

(d) The term "old unit" shall mean any generating unit, subject to the provisions of this part, of 500 megawatts or greater rated net generating capacity which was first placed in service on or before January 1, 1970 and any generating unit of less than 500 megawatts rated net generating capacity which was first placed in service on or before January 1, 1974.

(e) The term "blowdown" shall mean the minimum discharge of recirculating water for the purpose of discharging materials contained in the process, the further buildup of which would cause concentrations or amounts exceeding limits established by best engineering practice.

[40 FR 7095, February 19, 1975]

(f) The term "free available chlorine" shall mean the value obtained using the amperometric titration method for free available chlorine described in "Standard Methods for the Examination of Water and Wastewater", page 112 (13th edition).

(g) The term "sufficient land" shall mean 100 sq m (1100 sq ft) or more per megawatt of nameplate generating capacity.

(h) The term "low volume waste sources" shall mean, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established in this subpart. Low volume waste sources would include but are not limited to wastewaters from wet scrubber air pollution control systems, ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, floor drainage, cooling tower basin cleaning wastes and blowdown from recirculating house service water systems. Sanitary wastes and air conditioning wastes are specifically not included in low volume waste sources.

[40 FR 7095, February 19, 1975]

(i) The term "ash transport water" shall mean water used in the hydraulic transport of either fly ash or bottom ash.

(j) The term "metal cleaning wastes" shall mean any cleaning compounds, rinse waters, or any other waterborne residues derived from cleaning any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning and air preheater cleaning.

(k) The term "once through cooling water" shall mean water passed through the main cooling condensers in one or two passes for the purpose of removing waste heat from the generating unit.

(l) The term "recirculated cooling water" shall mean water which is passed through the main cooling condensers for the purpose of removing waste heat from the generating unit, passed through a cooling device for the purpose of removing such heat from the water and then passed again, except for blowdown, through the main cooling condensers.

[40 FR 7095, February 19, 1975]

(m) The term "cooling pond" shall mean any manmade water impoundment which does not impede the flow of a navigable stream and which is used to remove waste heat from heated condenser water prior to returning the recirculated cooling water to the main condenser.

(n) The term "cooling lake" shall mean any manmade water impoundment which impedes the flow of a navigable stream and which is used to remove waste heat from heated condenser water prior to recirculating the water to the main condenser.

§ 423.12 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available.

(a) In establishing the limitations set forth in this section, EPA took into account all information it was able to collect, develop and solicit with respect to factors (such as age and size of plant, utilization of facilities, raw materials, manufacturing processes, non-water quality environmental impacts, control and treatment technology available, energy requirements and costs) which can affect the industry subcategorization and effluent levels established. It is, however, possible that data which would affect these limitations have not been available and, as a result, these limitations should be adjusted for certain plants in this industry. An individual discharger or other interested person may submit evidence to the Regional Administrator (or to the State, if the State has the authority to issue NPDES permits) that factors relating to the equipment or facilities involved, the process applied, or other such factors related to such discharger are fundamentally different from the factors considered in the establishment of the guidelines. On the basis of such evidence or other available information, the Regional Administrator (or the State) will make a written finding that such factors are or are not fundamentally different for that facility compared to those specified in the Development Document. If such fundamentally different factors are found to exist, the Regional Administrator or the State shall establish for the discharger effluent limitations in the NPDES permit either more or less stringent than the limitations established herein, to the extent dictated by such fundamentally different factors. Such limitations must be approved by the Administrator of the Environmental Protection Agency. The Administrator may approve or disapprove such limitations, specify other limitations or initiate proceedings to revise these regulations.

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(b) The following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best practicable control technology currently available:

(1) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(2) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.
[40 FR 7095, February 19, 1975]

(3) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(4) The quantity of pollutants discharged in ash transport water shall not exceed the quantity determined by multiplying the flow of ash transport water times the concentration listed in the following table:
[40 FR 7095, February 19, 1975]

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(5) The quantity of pollutants discharged in metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(6) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(7) The quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(8) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(9) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or State, if the State has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10) In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b) (1) through (9) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

[40 FR 7095, February 19, 1975]

§ 423.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable.

The following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best available technology economically achievable:

(a) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0

(b) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.
[40 FR 7095, February 19, 1975]

(c) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(d) The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in the following table and dividing the product by 12.5:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(e) The quantity of pollutants discharged in fly ash transport water shall not exceed the quality determined by multiplying the flow of fly ash transport water times the concentration listed in the following table:
[40 FR 7095, February 19, 1975]

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(f) The quantity of pollutants discharged in metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(g) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(h) The quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:
[40 FR 7095, February 19, 1975]

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(i) The quantity of pollutants discharged from cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed in the following table:

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Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
Zinc	1.0 mg/l	1.0 mg/l.
Chromium	0.2 mg/l	0.2 mg/l.
Phosphorus	5.0 mg/l	5.0 mg/l.
Other corrosion inhibiting materials.	Limit to be established on a case by case basis.	

(j) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(k) In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (j) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

(l) There shall be no discharge of heat from the main condensers except:

(1) Heat may be discharged in blowdown from recirculated cooling water systems provided the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculating cooling water prior to the addition of the make-up water.

(2) Heat may be discharged in blowdown from recirculated cooling water systems which have been designed to discharge blowdown water at a temperature above the lowest temperature of recirculated cooling water prior to the addition of make-up water providing such recirculating cooling systems have been placed in operation or are under construction prior to the effective date of this regulation.

(3) Heat may be discharged in blowdown (overflow) from a cooling pond or cooling lake where the owner or operator of a unit otherwise subject to this limitation can demonstrate that a cooling pond, or cooling lake in service or under construction as of the effective date of this regulation, is used to cool recirculated cooling water before it is recirculated to the main condensers.

[40 FR 7095, February 19, 1975]

(4) Heat may be discharged where the owner or operator of a unit otherwise subject to this limitation can demonstrate that sufficient land for the construction and operation of mechanical draft evaporative cooling towers is not available (after consideration of alternate land use assignments) on the premises or on adjoining property under the ownership or control of the owner or operator as of March 4, 1974, and that no alternate recirculating cooling system is practicable.

(5) Heat may be discharged where the owner or operator of a unit otherwise subject to this limitation can demonstrate that the total dissolved solids concentration in blowdown exceeds 30,000 mg/l and land not owned or controlled by the owner or operator as of March 4, 1974, is located within 150 meters (500 feet) in the prevailing downwind direction of every practicable location for mechanical draft cooling towers and that no alternate recirculating cooling system is practicable.

(6) Heat may be discharged where the owner or operator of a unit otherwise subject to this limitation can demonstrate to the regional administrator or State, if the State has NPDES permit issuing authority, that the plume which must necessarily emit from a cooling tower would cause a substantial hazard to commercial aviation and that no alternate recirculated cooling water system is practicable. In making such demonstration to the regional administrator or State the owner or operator of such unit must include a finding by the Federal Aviation Administration that the visible plume emitted from a well-operated cooling tower would in fact cause a substantial hazard to commerical aviation in the vicinity of a major commercial airport.

(m) The limitation of paragraph "l" of this section shall become effective on July 1, 1981.

(n) In the event that a regional reliability council, or when no functioning regional reliability council exists, a major utility or consortium of utilities, can demonstrate to the regional administrator or State, if the State has NPDES permit issuing authority, that the system reliability would be seriously impacted by complying with the effective date set forth in paragraph (m) above, the regional administrator may accept an alternative proposed schedule of compliance on the part of all the utilities concerned providing, however, that such schedule of compliance will require that units representing not less than 50 percent of the affected generating capacity shall meet the compliance date, that units representing not less than an additional 30 percent of the generating capacity shall comply not later than July 1, 1982 and the balance of units shall comply not later than July 1, 1983.

§ 423.14 [Reserved]

§ 423.15 Standards of performance for new sources.

The following standards of performance establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a new source subject to the provisions of this subpart:

(a) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(b) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

[40 FR 7095, February 19, 1975]

(c) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(d) The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in the following table and dividing the product by 20:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(e) There shall be no discharge of TSS or oil and grease in fly ash transport water.

(f) The quantity of pollutants discharged from metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(g) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(h) The quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown sources times the concentration listed in the following table:

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Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l..........	0.2 mg/l.
	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
Materials added for corrosion inhibition including but not limited to zinc, chromium, Phosphorus.	No detectable amount.	No detectable amount.

(j) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(k) In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (j) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

(l) There shall be no discharge of heat from the main condensers except:

(1) Heat may be discharged in blowdown from recirculated cooling water systems provided the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water prior to the addition of the make-up water.

(2) Heat may be discharged in blowdown from cooling ponds provided the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water prior to the addition of the make-up water.

§ 423.16 Pretreatment standards for new sources.

The pretreatment standards under section 307(c) of the Act for a source within the generating unit subcategory, which is a user of a publicly owned treatment works (and which would be a new source subject to section 306 of the Act, if it were to discharge pollutants to the navigable waters), shall be the standard set forth in 40 CFR Part 128, except that, for the purpose of this section, 40 CFR 128.133 shall be amended to read as follows:

> In addition to the prohibitions set forth in 40 CFR 128.131, the pretreatment standard for incompatible pollutants introduced into a publicly owned treatment works shall be the standard of performance for new sources specified in 40 CFR 423.15 except for the following pollutants or pollutant parameters for which the following pretreatment standards are established:
>
> | Pollutant or pollutant parameter: | *Pretreatment standard* |
> |---|---|
> | Heat | No limitation. |
> | Free available chlorine | No limitation. |
> | Total residual chlorine | No limitation. |
>
> If the publicly owned treatment works which receives the pollutants is committed, in its NPDES permit, to remove a specified percentage of any incompatible pollutant, the pretreatment standard applicable to users of such treatment works shall, except in the case of standards providing for no discharge of pollutants, be correspondingly reduced in stringency for that pollutant.

[40 FR 7095, February 19, 1975]

Subpart D—Small Unit Subcategory

§ 423.20 Applicability: description of the small unit subcategory.

The provisions of this subpart are applicable to discharges resulting from the operation of a small unit by an establishment primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel (coal, oil, or gas) or nuclear fuel in conjunction with a thermal cycle employing the steam-water system as the thermodynamic medium.

§ 423.21 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided below, the general definitions, abbreviations and methods of analysis set forth in 40 CFR Part 401 shall apply to this subpart.

(b) The term "small unit" shall mean any generating unit subject to the provisions of this part, except a unit defined below as old, of less than 25 megawatts rated net generating capacity or any unit which is part of an electric utilities system with a total net generating capacity of less than 150 megawatts.

(c) The term "old unit" shall mean any generating unit, subject to the provisions of this part, of 500 megawatts or greater rated net generating capacity which was first placed in service on or before January 1, 1970 and any generating unit of less than 500 megawatts rated net generating capacity which was first placed in service on or before January 1, 1974.

(d) The term "blowdown" shall mean the minimum discharge of recirculating water for the purpose of discharging materials contained in the process, the further buildup of which would cause concentrations or amounts exceeding limits established by best engineering practice.

[40 FR 7095, February 19, 1975]

(e) The term "free available chlorine" shall mean the value obtained using the amperometric titration method for free available chlorine described in "Standard Methods for the Examination of Water and Wastewater", page 112 (13th Edition).

(f) The term "low volume waste sources" shall mean, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established in this subpart. Low volume waste sources would include but are not limited to wastewaters from wet scrubber air pollution control systems, ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, floor drainage, cooling tower basin cleaning wastes and blowdown from recirculating house service water systems. Sanitary wastes and air conditioning wastes are specifically not included in low volume waste sources.

[40 FR 7095, February 19, 1975]

(g) The term "ash transport water" shall mean water used in the hydraulic transport of either fly ash or bottom ash.

(h) The term "metal cleaning wastes" shall mean any cleaning compounds rinse waters, or any other waterborne residues derived from cleaning any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning and air preheater cleaning.

(i) The term "once through cooling water" shall mean water passed through the main cooling condensers in one or two passes for the purpose of removing waste heat from the generating unit.

(j) The term "recirculated cooling water" shall mean water which is passed through the main cooling condensers for the purpose of removing waste heat from the generating unit, [illegible]ed through a cooling device for the purpose of removing such heat from the water and then passed again, except for blowdown, through the main cooling condensers.

[40 FR 7095, February 19, 1975]

(k) The term "cooling pond" shall mean any manmade water impoundment which does not impede the flow of a navigable stream and which is used to remove waste heat from heated condenser water prior to returning the recirculated cooling water to the main condenser.

§ 423.22 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available.

(a) In establishing the limitations set forth in this section, EPA took into account all information it was able to collect, develop and solicit with respect to factors (such as age and size of plant, utilization of facilities, raw materials, manufacturing processes, non-water quality environmental impacts, control and treatment technology available, energy requirements and costs) which can affect the industry subcategorization and effluent levels established. It is, however, possible that data which would affect these limitations have not been available and, as a result, these limitations should be adjusted for certain plants in this industry. An individual discharger or other interested person may submit evidence to the Regional Administrator (or to the State, if the State has the authority to issue NPDES permits) that factors relating to the equipment or facilities involved, the process applied, or other such factors related to such discharger are fundamentally different

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from the factors considered in the establishment of the guidelines. On the basis of such evidence or other available information, the Regional Administrator (or the State) will make a written finding that such factors are or are not fundamentally different for that facility compared to those specified in the Development Document. If such fundamentally different factors are found to exist, the Regional Administrator or the State shall establish for the discharger effluent limitations in the NPDES permit either more or less stringent than the limitations established herein, to the extent dictated by such fundamentally different factors. Such limitations must be approved by the Administrator of the Environmental Protection Agency. The Administrator may approve or disapprove such limitations, specify other limitations, or initiate proceedings to revise these regulations.

(b) The following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best practicable control technology currently available:

(1) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(2) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

[40 FR 7095, February 19, 1975]

(3) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l

(4) The quantity of pollutants discharged in ash transport water shall not exceed the quantity determined by multiplying the flow of ash transport water times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l

(5) The quantity of pollutants discharged in metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
Copper, Total	1.0 mg/l	1.0 mg/l
Iron, Total	1.0 mg/l	1.0 mg/l

(6) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
Copper, Total	1.0 mg/l	1.0 mg/l
Iron, Total	1.0 mg/l	1.0 mg/l

(7) The quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l

(8) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l

(9) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10) In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b) (1) through (9) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

[40 FR 7095, February 19, 1975]

§ 423.23 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable.

The following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best available technology economically achievable:

(a) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(b) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

(c) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l

(d) The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in the following table and dividing the product by 12.5:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l

(e) The quantity of pollutants discharged in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l

(f) The quantity of pollutants discharged in metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
Copper, Total	1.0 mg/l	1.0 mg/l
Iron, Total	1.0 mg/l	1.0 mg/l

(g) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l
Oil and Grease	20 mg/l	15 mg/l
Copper, Total	1.0 mg/l	1.0 mg/l
Iron, Total	1.0 mg/l	1.0 mg/l

(h) The quantity of pollutants discharged in once through condenser water shall not exceed the quantity determined by multiplying the flow of once through condenser water sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.
	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
Zinc	1.0 mg/l	1.0 mg/l.
Chromium	0.2 mg/l	0.2 mg/l.
Phosphorus	5.0 mg/l	5.0 mg/l.
Other corrosion inhibiting materials.	Limit to be established on a case by case basis.	

[40 FR 7095, February 19, 1975]

(j) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(k) In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (j) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

§ 423.24 [Reserved]

§ 423.25 Standards of performance fo. new sources.

The following standards of performance establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a new source subject to the provisions of this subpart:

(a) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(b) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

[40 FR 7095, February 19, 1975]

(c) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l

(d) The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in the following table and dividing the product by 20:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(e) There shall be no discharge of TSS or oil and grease in fly ash transport water.

(f) The quantity of pollutants discharged in metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(g) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(h) The quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.
	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
Materials added for corrosion inhibition including zinc, chromium, phosphorus and others.	No detectable amount.	No detectable amount.

(j) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(k) In the event that waste steams from various sources are combined for treatment, or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (j) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

(l) There shall be no discharge of heat from the main condensers except:

(1) Heat may be discharged in blowdown from recirculated cooling water systems provided the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water prior to the addition of the make-up water.

(2) Heat may be discharged in blowdown from cooling ponds provided the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water prior to the addition of the make-up water.

§ 423.26 Pretreatment standards for new sources.

The pretreatment standards under section 307(c) of the Act for a source within the small unit subcategory, which is a user of a publicly owned treatment works (and which would be a new source subject to section 306 of the Act, if it were to discharge pollutants to the navigable waters), shall be the standard set forth in 40 CFR Part 128, except that, for the purpose of this section, 40 CFR 128.133 shall be amended to read as follows:

In addition to the prohibitions set forth in 40 CFR 128.131, the pretreatment standard for incompatible pollutants introduced into a publicly owned treatment works shall be the standard of performance for new sources specified in 40 CFR 423.25 except for the following pollutants or pollutant parameters for which the following pretreatment standards are established:

Pollutant or pollutant parameter	*Pretreatment standard*
Heat	No limitation.
Free available chlorine.	No limitation.
Total residual chlorine.	No limitation.

If the publicly owned treatment works which receives the pollutants is committed, in its NPDES permit, to remove a specified percentage of any incompatible pollutant, the pretreatment standard applicable to users of such treatment works shall, except in the case of standards providing for no discharge of pollutants, be correspondingly reduced in stringency for that pollutant.

[40 FR 7095, February 19, 1975]

Subpart C—Old Unit Subcategory

§ 423.30 Applicability; description of the old unit subcategory.

The provisions of this subpart are applicable to discharges resulting from the operation of an old unit by an establishment primarily engaged in the generation of electricity for distribution and sale which results primarily from a process utilizing fossil-type fuel (coal, oil, gas) or nuclear fuel in conjunction with a thermal cycle employing the steam-water system as the thermodynamic medium.

[40 FR 7095, February 19, 1975]

§ 423.31 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided below, the general definitions, abbreviations and methods of analysis set forth in 40 CFR Part 401 shall apply to this subpart.

(b) The term "old unit" shall mean any generating unit, subject to the provisions of this part, of 500 megawatts or greater rated net generating capacity which was first placed in service on or before January 1, 1970 and any generating unit of less than 500 megawatts rated net generating capacity which was first placed in service on or before January 1, 1974.

(c) The term "blowdown" shall mean the minimum discharge of recirculating water for the purpose of discharging materials contained in the process, the further buildup of which would cause concentrations or amounts exceeding limits established by best engineering practice.

[40 FR 7095, February 19, 1975]

(d) The term "free available chlorine" shall mean the value obtained using the amperometric titration method for free available chlorine described in "Standard Methods for the Examination of Water and Wastewater", page 112 (13th Edition).

(e) The term "low volume waste sources" shall mean, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established in this subpart. Low volume waste sources would include but are not limited to wastewaters from wet scrubber air pollution control systems, ion exchange water treatment systems, water treatment evaporator blowdown, laboratory and sampling streams, floor drainage, cooling tower basin cleaning wastes and blowdown from recirculating house service water systems. Sanitary wastes and air conditioning wastes are specifically not included in low volume waste sources.

[40 FR 7095, February 19, 1975]

(f) The term "ash transport water" shall mean water used in the hydraulic transport of either fly ash or bottom ash.

(g) The term "metal cleaning wastes" shall mean any cleaning compounds, rinse waters, or any other waterborne residues derived from cleaning any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning and air preheater cleaning.

(h) The term "once through cooling water" shall mean water passed through the main cooling condensers in one or two passes for the purpose of removing waste heat from the generating unit.

[40 FR 7095, February 19, 1975]

(i) The term "recirculated cooling water" shall mean water which is passed through the main cooling condensers for the purpose of removing waste heat from the generating unit, passed through a cooling device for the purpose of removing such heat from the water and then passed again, except for blowdown, through the main cooling condensers.

[40 FR 7095, February 19, 1975]

§ 423.32 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available.

(a) In establishing the limitations set forth in this section, EPA took into account all information it was able to collect, develop and solicit with respect to factors (such as age and size of plant, utilization of facilities, raw materials, manufacturing processes, non-water quality environmental impacts, control and treatment technology available, energy requirements and costs) which can affect the industry subcategorization and effluent levels established. It is, however, possible that data which would affect these limitations have not been available and, as a result, these limitations should be adjusted for certain plants in this industry. An individual discharger or other interested person may submit evidence to the Regional Administrator (or to the State, if the State has the authority to issue NPDES permits) that factors relating to the equipment or facilities involved the process applied, or other such factors related to such discharger are fundamentally different from the factors considered in the establishment of the guidelines. On the basis of such evidence or other available information, the Regional Administrator (or the State) will make a written finding that such factors are or are not fundamentally different for that facility compared to those specified in the Development Document. If such fundamentally different factors are found to exist, the Regional Administrator or the State shall establish for the discharger effluent limitations in the NPDES permit either more or less stringent than the limitations established herein, to the extent dictated by such fundamentally different factors. Such limitations must be approved by the Administrator of the Environmental Protection Agency. The Administrator may approve or disapprove such limitations, specify other limitations, or initiate proceedings to revise these regulations.

(b) The following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best practicable control technology currently available:

(1) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(2) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

[40 FR 7095, February 19, 1975]

(3) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(4) The quantity of pollutants discharged in ash transport water shall not exceed the quantity determined by multiplying the flow of ash transport water times the concentration listed in the following table.

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(5) The quantity of pollutants discharged in metal cleaning wastes shall not exceed the quanuty determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed—
TSS	00 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

Effluent characteristic	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed—
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(6) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

(7) The quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

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Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(8) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

(9) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(10) In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (b) (1) through (9) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

[40 FR 7095, February 19, 1975]

§ 423.33 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable.

The following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best available technology:
available technology economically achievable.
[40 FR 7095, February 19, 1975]

(a) The pH of all discharges, except once through cooling water, shall be within the range of 6.0–9.0.

(b) There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid.

[40 FR 7095, February 19, 1975]

(c) The quantity of pollutants discharged from low volume waste sources shall not exceed the quantity determined by multiplying the flow of low volume waste sources times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed—
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(d) The quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in the following table and dividing the product by 12.5:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed—
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(e) The quantity of pollutants discharged in fly ash transport water shall not exceed the quantity determined by multiplying the flow of fly ash transport water times the concentration listed in the following table:

Effluent characteristic	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed—
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.

(f) The quantity of pollutants discharged in metal cleaning wastes shall not exceed the quantity determined by multiplying the flow of metal cleaning wastes times the concentration listed in the following table:

Effluent characteristic	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed—
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(g) The quantity of pollutants discharged in boiler blowdown shall not exceed the quantity determined by multiplying the flow of boiler blowdown times the concentration listed in the following table:

Effluent characteristic	Maximum for any one day	Average of daily values for thirty consecutive days shall not exceed
TSS	100 mg/l	30 mg/l.
Oil and Grease	20 mg/l	15 mg/l.
Copper, Total	1.0 mg/l	1.0 mg/l.
Iron, Total	1.0 mg/l	1.0 mg/l.

(h) The quantity of pollutants discharged in once through cooling water shall not exceed the quantity determined by multiplying the flow of once through cooling water sources times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.

[40 FR 7095, February 19, 1975]

(i) The quantity of pollutants discharged in cooling tower blowdown shall not exceed the quantity determined by multiplying the flow of cooling tower blowdown times the concentration listed in the following table:

Effluent Characteristic	Maximum Concentration	Average Concentration
Free available chlorine.	0.5 mg/l	0.2 mg/l.
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed—
Zinc	1.0 mg/l	1.0 mg/l.
Chromium	0.2 mg/l	0.2 mg/l.
Phosphorus	5.0 mg/l	5.0 mg/l.
Other corrosion inhibiting materials.	Limit to be established on a case by case basis.	

[40 FR 7095, February 19, 1975]

(j) Neither free available chlorine nor total residual chlorine may be discharged from any unit for more than two hours in any one day and not more than one unit in any plant may discharge free available or total residual chlorine at any one time unless the utility can demonstrate to the regional administrator or state, if the state has NPDES permit issuing authority, that the units in a particular location cannot operate at or below this level of chlorination.

(k) In the event that waste streams from various sources are combined for treatment or discharge, the quantity of each pollutant or pollutant property controlled in paragraphs (a) through (j) of this section attributable to each controlled waste source shall not exceed the specified limitation for that waste source.

§ 423.34 [Reserved]

Subpart D—Area Runoff Subcategory

§ 423.40 Applicability; description of the area runoff subcategory.

The provisions of this subpart are applicable to discharges resulting from material storage runoff and construction runoff which are used in or derived from units subject to the limitations in subparts A, B, or C of this part.

[40 FR 7095, February 19, 1975]

§ 423.41 Specialized definitions.

For the purpose of this subpart:

(a) Except as provided below, the general definitions, abbreviations and methods of analysis set forth in 40 CFR Part 401 shall apply to this subpart.

(b) The term "material storage runoff" shall mean the rainfall runoff from or through any coal, ash or other material storage pile.

(c) The term "construction runoff" shall mean the point source rainfall runoff from a construction activity and any earth surface disturbed by such activity from the inception of the construction until construction is complete and any disturbed earth is returned to a vegetative or other cover commensurate with the intended land use.

[40 FR 7095, February 19, 1975]

(d) The term "10 year, 24 hour rainfall event" shall mean a rainfall event with a probable recurrence interval of once in ten years as defined by the National Weather Service in Technical Paper No. 40, "Rainfall Frequency Atlas of the United States," May 1961, and subsequent amendments, or equivalent regional or State rainfall probability information developed therefrom.

§ 423.42 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best practicable control technology currently available.

In establishing the limitations set forth in this section, EPA took into account all information it was able to collect, develop and solicit with respect to factors (such as age and size of plant, utilization of facilities, raw materials, manufacturing processes, non-water quality environmental impacts, control and treatment technology available, energy requirements and costs) which can affect the industry subcategorization and effluent levels established. It is, however, possible that data which would affect these limitations have not been available and, as a result, these limitations should be adjusted for certain plants in this industry. An individual discharger or other interested person may submit evidence to the Regional Administrator (or to the State, if the State has the authority to issue NPDES permits) that factors relating to the equipment or facilities involved, the process applied, or other such factors related to such discharger are fundamentally different from the factors considered in the establishment of the guidelines. On the basis of such evidence or other available information, the Regional Administrator (or the State) will make a written finding that such factors are or are not fundamentally different for that facility compared to those specified in the Development Document. If such fundamentally different factors are found to exist, the Regional Administrator or the State shall establish for the discharger effluent limitations in the NPDES permit either more or less stringent than the limitations established herein, to the extent dictated by such fundamentally different factors. Such limitations must be approved by the Administrator of the Environmental Protection Agency. The Administrator may approve or disapprove such limitations, specify other limitations, or initiate proceedings to revise these regulations.

(a) Subject to the provisions of paragraph (b) of this section, the following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best practicable control technology currently available:

Effluent characteristic:	*Effluent limitations*
TSS	Not to exceed 50 mg/l.
ph	Within the range 6.0 to 9.0.

(b) Any untreated overflow from facilities designed, constructed and operated to treat the volume of material storage runoff and construction runoff which is associated with a 10 year, 24 hour rainfall event shall not be subject to the limitations in subparagraph (a) of this section.

§ 423.43 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable.

(a) Subject to the provisions of paragraph (b) of this section, the following limitations establish the quantity or quality of pollutants or pollutant properties, controlled by this section, which may be discharged by a point source subject to the provisions of this subpart after application of the best practicable control technology currently available:

Effluent characteristic:	*Effluent limitations*
TSS	Not to exceed 50 mg/l.
ph	Within the range 6.0 to 9.0.

(b) Any untreated overflow from facilities designed, constructed and operated to treat the volume of material storage runoff and construction runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the limitations in paragraph (a) of this section.

§ 423.44 [Reserved]

§ 423.45 Standards of performance for new sources.

(a) Subject to the provisions of paragraph (b) of this section, the following standards of performance establish the quantity or quality of pollutants or pollutant properties, which may be discharged by a new source subject to the provisions of this subpart:

Effluent characteristic:	*Effluent limitations*
TSS	Not to exceed 50 mg/l.
ph	Within the range 6.0 to 9.0.

(b) Any untreated overflow from facilities designed, constructed and operated to treat the volume of material storage runoff and construction runoff which results from a 10 year, 24 hour rainfall event shall not be subject to the ph and TSS limitations stipulated in paragraph (a) of this section.

§ 423.46 Pretreatment standards for new sources.

The pretreatment standards under section 307(c) of the Act for a source within the area runoff subcategory, which is a user of a publicly owned treatment works (and which would be a new source subject to section 306 of the Act, if it were to discharge pollutants to the navigable waters), shall be the standard set forth in 40 CFR Part 128, except that, for the purpose of this section, 40 CFR 128.133 shall be amended to read as follows:

> In addition to the prohibitions set forth in 40 CFR 128.131, the pretreatment standard for incompatible pollutants introduced into a publicly owned treatment works shall be the standard of performance for new sources specified in 40 CFR 423.45: *Provided*, That, if the publicly owned treatment works which receives the pollutants is committed, in its NPDES permit, to remove a specified percentage of any incompatible pollutant, the pretreatment standard applicable to users of such treatment works shall, except in the case of standards providing for no discharge of pollutants, be correspondingly reduced in stringency for that pollutant.

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APPENDIX E

COMBUSTION CLASSIFICATION SYSTEM

The rows of the summary tables, as presented in the main body of this report, define the combustion systems to be evaluated for air, water, and solid waste pollutants. These systems are identified by function, combustion type (external or internal), fuel, furnace type, and firing method. A classification coding system identifying the above factors, and others such as size, the use of fly ash reinjection, and control device application, has been developed to aid in the possible computerization of the data base.

The specific classifications used in the summary tables were chosen primarily to identify factors that affect pollutant properties or quantities or to indicate the state-of-the-art of combustion technology. Table 165 presents an overview of the Combustion System Classification by listing the function, combustion types and fuels for the electric generation function and combustion type for the industrial, commercial and residential functions. Table 166 further expands the classification system to include all of the factors that can be used to define the system discussed in Section II of the report for Electric Generation-External Combustion-Bituminous Coal-Pulverized Dry-Tangential Firing. This table is also condensed since a full expansion of all classifications under the above heading by Electric Generation-External Combustion-Bituminous Coal would require 576 rows to include furnace types, firing patterns, size and fly ash reinjection (excluding control devices). If full use is to be made of this classification system, the need for computerization is obvious. Computerization will require also that a classification coding system be developed for the unit processes and pollutants which comprise the columns of the summary tables. Approximately 300 columns have been used in this document to define the pollutants emitted from combustion sources and their associated operations.

Table 165. OVERVIEW OF COMBUSTION CLASSIFICATION SYSTEM

1.0.00.0.0	Electric Generation
1.1.00.0.0	External Combustion (all fuels)
1.1.10.0.0	Coal
1.1.11.0.0	Bituminous
1.1.12.0.0	Anthracite
1.1.13.0.0	Lignite
1.1.20.0.0	Petroleum
1.1.21.0.0	Residual Oil
1.1.22.0.0	Distillate Oil
1.1.23.0.0	Crude Oil
1.1.24.0.0	Kerosene
1.1.25.0.0	Diesel Fuel
1.1.26.0.0	Gasoline
1.1.30.0.0	Gas
1.1.31.0.0	Natural Gas
1.1.32.0.0	Process Gas
1.1.33.0.0	LPG
1.1.40.0.0	Waste
1.1.41.0.0	Bagasse
1.1.42.0.0	Wood/Back
1.1.43.0.0	Other
1.2.00.0.0	Internal Combustion (All)
1.3.00.0.0	Internal Combustion - Turbines
1.4.00.0.0	Internal Combustion - Reciprocating
1.4.20.0.0	Petroleum
1.4.22.0.0	Distillate Oil
1.4.30.0.0	Gas
1.4.31.0.0	Natural Gas
2.0.00.0.0	Industrial
2.1.00.0.0	External Combustion
2.2.00.0.0	Internal Combustion
3.0.00.0.0	Commercial
3.1.00.0.0	External Combustion
3.2.00.0.0	Internal Combustion
4.0.00.0.0	Residential
4.1.00.0.0	External Combustion

Table 166. EXAMPLE OF COMBUSTION CLASSIFICATION SYSTEM FOR ELECTRIC GENERATION, EXTERNAL COMBUSTION

1.0.00.0.0	Electric Generation
1.1.00.0.0	External Combustion
1.1.10.0.0	Coal
1.1.11.0.0	Bituminous
1.1.11.1.0	Pulverized Dry
1.1.11.1.1	Tangential
1.1.11.1.1.1	> 5000 x 10^6 Btu/hr
1.1.11.1.1.2	1500 - 5000 x 10^6 Btu/hr
1.1.11.1.1.3	500 - 1500 x 10^6 Btu/hr
1.1.11.1.1.3.1	with fly ash reinjection
1.1.11.1.1.3.1.1	with ESP
1.1.11.1.1.3.1.1.1	with ESP and limestone scrubber
1.1.11.1.1.3.1.1.1.1	with ESP, limestone scrubber and staged firing
1.1.11.1.1.3.1.x.x.1	with staged firing: no other control device

APPENDIX F

CONVERSION FACTORS

CAPACITY, ENERGY, FORCE, HEAT

Multiply	By	To obtain
Btu	0.2520	Kilogram-calories
Btu/min	3.927×10^{-4}	Horsepower-hrs
Btu/min	2.928×10^{-4}	Kilowatt-hrs
Btu/min	0.02356	Horsepower
Btu/min	0.01757	Kilowatts
Btu/min	10^{-3}	Pound/hr steam
Horsepower (boiler)	33,479	Btu/hr
Horsepower (boiler)	9.803	Kilowatts
Horsepower-hours	0.7457	Kilowatt-hours
Kilowatts	56.92	Btu/min
Kilowatts	1.341	Horsepower
Kilowatt-hours	3415	Btu
Kilowatt-hours	1.341	Horsepower-hrs
Megawatts	1360	Kilogram/hr steam
Pound/hr steam	0.454	Kg/hr

Energy equivalences of various fuels:

Bituminous coal - 22.4×10^6 Btu/ton, 1971-1973
21.9×10^6 Btu/ton, 1974

Anthracite coal - 26.0×10^6 Btu/ton

Lignite coal - 16.0×10^6 Btu/ton

Residual oil - 147,000 Btu/gal

Distillate oil - 140,000 Btu/gal

Natural gas - 1,022 Btu/ft^3

1 lb of water evaporated from and at 212°F equals:

0.2844 Kilowatt-hours
0.3814 Horsepower-hours
970.2 Btu

FLOW

Multiply	By	To obtain
Cubic feet/minute	0.1247	Gallons/sec.
Cubic feet/second	0.646317	Million gals/day
Cubic feet/second	448.831	Gallons/min
Cubic meter/sec.	22.8	Million gals/day
Cubic meter/sec.	8.32×10^{9}	Gallons/year
Gallons/year	10.37×10^{-6}	m^3/day
Gallons/min.	2.228×10^{-3}	Cubic feet/sec.
Liters/min.	5.886×10^{-4}	Cubic ft/sec,
Liters/min.	4.403×10^{-3}	Gals/sec.
Million gals/day	1.54723	Cubic ft/sec.
Million gals/day	0.044	Cubic meters.secibd
Million gals/day	695	Gallons/min.
Pounds of water/min.	2.679×10^{-4}	Cubic ft/sec.

LENGTH, AREA, VOLUME

Multiply	By	To obtain
Acres	43,560	Square feet
Acres	4047	Square meters
Acres	1.562×10^{-3}	Square miles
Acre-feet	43,560	Cubic feet
Acre-feet	325,851	Gallons
Acre-feet	1233.49	Cubic meters
Barrels-oil	0.156	Cubic meters
Barrels-oil	42	Gallons-oil
Centimeters	0.3937	Inches
Cubic feet	2.832×10^{4}	Cubic cms.
Cubic feet	1728	Cubic inches
Cubic feet	0.02832	Cubic meters
Cubic feet	0.03704	Cubic yards
Cubic feet	7.48052	Gallons
Cubic feet	28.32	Liters
Cubic meters	35.31	Cubic feet
Cubic meters	264.2	Gallons
Feet	30.48	Centimeters
Feet	0.3048	Meters

Gallons	0.1337	Cubic feet
Gallons	3.785×10^{-3}	Cubic meters
Gallons, Imperial	1.20095	U.S. gallons
Gallons water	8.3453	Pounds of water
Liters	0.2642	Gallons
Meters	3.281	Feet
Meters	39.37	Inches
Square feet	2.296×10^{-5}	Acres
Square feet	0.09290	Square meters
Square meters	2.471×10^{-4}	Acres
Square meters	10.76	Square feet
Square miles	640	Acres

MASS, PRESSURE, TEMPERATURE, CONCENTRATION

Multiply	By	To obtain
Atmospheres	29.92	Inches of mercury
Atmospheres	33.90	Feet of water
Atmospheres	14.70	Lbs/sq. inch
Grams	15.43	Grains (troy)
Grams/liter	58.417	Grains/gal
Grams/liter	8.345	Pounds/1000 gals.
Grams/liter	0.062427	Pounds/cubic ft
Kilograms	2.2046	Pounds
Parts/million	0.0584	Grains/U.S. gal
Parts/million	8.345	Lbs/million gal
Pounds	453.5924	Grams
Pounds of water	0.01602	Cubic feet
Pounds of water	0.1198	Gallons
Pounds/sq. inch	0.06804	Atmospheres
Pounds/sq. inch	2.307	Feet of water
Pounds/sq. inch	2.036	Inches of mercury
Temp. ($^{\circ}$C) + 17.78	1.8	Temp. ($^{\circ}$F.)
Temp. ($^{\circ}$F) - 32	0.555	Temp. ($^{\circ}$C.)
Tons (metric)	2205	Pounds
Tons (short)	2000	Pounds
Tons (short)	0.89287	Tons (long)
Tons (short)	0.9975	Tons (metric)

APPENDIX G

MAJOR ACRONYMS USED IN THIS REPORT

ABMA	American Boiler Manufacturer's Association
ASME	American Society of Mechanical Engineers
BaP	Benzo(a)pyrene
BOD	Biological Oxygen Demand
BSO	Benzene Soluble Organics
Btu	British Thermal Units
COD	Chemical Oxygen Demand
EPA	Environmental Protection Agency
FGC	Flue Gas Cleaning
FGD	Flue Gas Desulfurization
FEA	Federal Energy Administration
FPC	Federal Power Commission
IERL	Industrial Environmental Research Laboratory
kWh	Kilowatt Hours
MR	Municipal Refuse
MW	Megawatts
MWh	Megawatt Hours
NEDS	National Emission Data System
NPDES	National Pollution Discharge Elimination System
PBB	Polybrominated Biphenyls
PCB	Polychlorinated Biphenyls
PHH	Polyhalogenated Hydrocarbons
POM	Polycyclic Organic Matter
PPOM	Particulate Polycyclic Organic Matter
SOTDAT	Source Test Data System

TS	Total Solids
TDS	Total Dissolved Solids
TSS	Total Suspended Solids
TLV	Threshold Limit Value
TVA	Tennessee Valley Authority